**DIRECT TESTIMONY OF ARNE OLSON
ON BEHALF OF
THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE**

EXHIBIT AO-1

Arne Olson

44 Montgomery Street, Suite 1500, San Francisco, CA 94104 415.391.5100, ext. 307
arne@ethree.com

ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner

Mr. Olson joined E3 in 2002 and became a partner in 2010. Mr. Olson helps clients navigate changes to bulk electric system operations and investment needs brought about by policies promoting clean and renewable energy production. He led the technical analysis and drafting of the landmark 2014 report *Investigating a Higher Renewable Portfolio Standard for California*, prepared for the five largest utilities in California, which delineated the challenges of achieving higher renewable penetrations as well as the many solutions that are available to ease the integration burden. Since that time, he has overseen E3's fast-growing resource planning practice which has completed numerous studies of deeply-decarbonized and highly-renewable power systems in California, Hawaii, the Pacific Northwest, the Desert Southwest, New York, South Africa, and many other regions.

He has also led the development of E3's industry-leading resource planning software including the RESOLVE model that develops optimal portfolios of renewable, conventional and energy storage resources to meet electric energy, capacity, and reliability needs while meeting specified policy goals including GHG caps and minimum renewable penetration levels and the RECAP model that calculates Loss-of-Load Probability and related statistics to ensure that power systems can meet load reliably under high renewable penetrations. His clients have included most of the major utilities and market participants in the West including the California Independent System Operator, Pacific Gas and Electric, Southern California Edison, Puget Sound Energy, PacifiCorp, Arizona Public Service, Sacramento Municipal Utilities District, Los Angeles Department of Water and Power, the Bonneville Power Administration, Calpine, NextEra, NRG, TransAlta and many others. He also works extensively with government agencies and industry organizations such as the California Public Utilities Commission, California Energy Commission, Oregon Public Utilities Commission, the Western Electric Coordinating Council, and the Western Interstate Energy Board. Other clients have included Florida Power & Light, Tampa Electric Company, Nova Scotia Power, Hydro-Quebec TransEnergie, TransElect, Long Island Power Authority, and others.

Resource Planning and Valuation:

- Led an award-winning project that investigated the value of operating solar power plants flexibly, including for the provision of essential grid services, on behalf of First Solar and with the assistance of Tampa Electric Company.
- Led a project that investigated the cost-effectiveness of alternative policies for decarbonizing the Northwest electric system on behalf of a group of generation-owning public power utilities.
- Led a team that is evaluating the need for flexible generation capacity on behalf of Portland General Electric.
- Led a team that assessed electricity-natural gas infrastructure issues on behalf of the Western Interstate Energy Board.

- Led a team that investigated the capacity contribution of new wind, solar and demand response (DR) resources on behalf of the Sacramento Municipal Utilities District.
- Assisted the Colorado Public Utilities Commission in developing long-term scenarios to use across a range of energy infrastructure planning dockets.
- Assisted BC Hydro in evaluating the impact of BC's provincial greenhouse gas reduction policies on future electric load as part of BC Hydro's 2011 Integrated Resource Plan.
- Provided expert testimony in front of the California Public Utilities Commission on rates and revenue requirements associated with several alternative portfolios of demand-side and supply-side resources, on behalf of Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric.
- Served as lead investigator in assisting the California Public Utilities Commission (CPUC) in its efforts to reform the long-term procurement planning process in order to allow California to meet its aggressive renewable energy and greenhouse gas reduction policy goals.
- Prepared an integrated resource plan (IRP) on behalf of Umatilla Electric Cooperative, a 200-MW electric cooperative based in Hermiston, Oregon. The IRP considered a number of different resource and rate product options, and addressed ways in which demand-side measures such as energy efficiency, distributed generation and demand response can help UEC reduce its wholesale energy and bulk transmission costs.
- Served as lead investigator in developing integrated resource plans for numerous publicly-owned utilities including PNGC Power, Lower Valley Energy, and Platte River Power Authority.
- Provided generation and transmission asset valuation services to a number of utility and independent developer clients.

<u>*Renewables and Emerging Technology:*</u>

- Currently leading a team that is advising Portland General Electric Company on potential strategies for cost-effective procurement of distributed or utility scale solar generation.
- Led a project that evaluated flexible capacity needs under high renewable penetration across the Western Interconnection on behalf of the Western Electric Coordinating Council and the Western Interstate Energy Board. The team included technical contributions from E3, NREL and Energy Exemplar.
- Led the technical analysis and drafting of the influential report *Investigating a Higher Renewable Portfolio Standard for California*. The report evaluated the operational challenges, costs and solutions for integrating a 40% or 50% Renewable Portfolio Standard on behalf of the five largest utilities in California.
- Led the team that developed the Renewable Energy Flexibility (REFLEX) model, commercial software that assesses power system flexibility needs under high renewable penetration.
- Led the team that developed the Renewable Energy Capacity Planning (RECAP) model, commercial software that calculates reliability metrics such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE) and Planning Reserve Margin (PRM), along with Effective Load-Carrying Capability (ELCC) of wind and solar resource, demand response programs, and other dispatch-limited resources.
- Currently advising the CPUC on renewable energy resource policy and procurement.
- Currently leading the California Independent System Operator's (CAISO) renewable integration needs studies. The studies are evaluating the need for firming capacity and flexible resources to accommodate the variable and unpredictable nature of wind and solar generation. Results of the studies will be used to determine the need to procure new, flexible resources.

- Led the team that developed renewable and conventional resource cost and performance characteristics for use in the WECC's Regional Transmission Expansion Planning process.
- On behalf of the Wyoming Governor's Office, developed a model of the cost of developing wind resources in Wyoming relative to neighboring states to inform policy debate regarding taxation. The model included detailed representations of state-specific taxes and capacity factors.
- On behalf of the CPUC, investigated a number of strategies for achieving a 33% Renewables Portfolio Standard in California by 2020, and estimated their likely cost and rate impacts using the 33% RPS Calculator, a publicly-available spreadsheet model developed for this project.
- Evaluated market opportunities and provided strategic advice for renewable energy developers in California and the Southwest.
- Investigated for Bonneville Power Administration (BPA) the economics and feasibility of investing in new, long-line transmission facilities connecting load centers in the Pacific Northwest with remote areas that contain large concentrations of high-quality renewable energy resources. The study informed BPA about cost-effective strategies for procuring renewable energy supplies in order to meet current and potential future renewable renewables portfolio standards and greenhouse gas reduction targets.
- Co-authored *Load-Resource Balance in the Western Interconnection: Towards 2020*, a study of west-wide infrastructure needs for achieving aggressive RPS and greenhouse gas reduction goals in 2020 for the Western Electric Industry Leaders (WEIL) Group, comprised of CEOs and executives from a number of utilities through the West, and presented results indicating that developing new transmission infrastructure to integrate remote renewable resources can result in cost savings for consumers under aggressive policy assumptions.

Transmission Planning and Pricing:

- Currently serving as technical support to the Western Electric Coordinating Council's Scenario Planning Steering Group (SPSG). The SPSG is developing scenarios for long-term transmission planning in the Western Interconnection.
- Currently advising several transmission developers seeking approval for projects through the CAISO's Transmission Planning Process.
- Led a team that investigated the use of Production Cost Modeling for the purpose of allocating costs of new transmission facilities on behalf of the Northern Tier Transmission Group, and contributed to NTTG's Order 1000 compliance filing.
- Served as an expert witness in front of the Alberta Utilities Commission in a case regarding the Alberta Electric System Operator's proposed methodology for allocating Available Transmission Capacity among interties during times of congestion.
- Led studies in 2009, 2011 and 2012 to develop generation and transmission capital cost assumptions for use in WECC's Transmission Expansion Planning and Policy Committee (TEPPC) studies.
- Contributed to a study of the benefits of North-South transmission expansion in Alberta on behalf of AltaLink.
- Led a study for WECC to estimate the benefits of developing a centralized Energy Imbalance Market (EIM) across the Western Interconnection. The study estimated benefits due to increased generation dispatch efficiency resulting from reduced market barriers and increased load and resource diversity among western Balancing Authorities. Led several follow-up studies of alternative Western EIM footprints for potential EIM participants.
- Retained by a consortium of southwestern utilities and state agencies including the Wyoming Infrastructure Authority, Xcel Colorado, Public Service Company of New Mexico, and the Salt

River Project to perform an economic feasibility study of the proposed High Plains Express (HPX) transmission project, a roadmap for transmission development in the Desert Southwest and Rocky Mountain regions.

- Provided assistance to the Seattle City Council to develop guidelines for the evaluation of large electric distribution and transmission projects by Seattle City Light (SCL). Guidelines specified the types of evaluations SCL should perform and the information the utility should present to the City Council when it seeks approval for large distribution or transmission projects.
- Conducted screening studies of long-distance transmission lines connecting to remote renewable energy zones for multiple western utilities.
- Assisted in the development of a methodology for evaluating the renewable energy benefits of the Sunrise Powerlink transmission project in support of expert testimony on behalf of the California ISO.
- Assisted British Columbia Transmission Corporation and Hydro-Quebec TransEnergie with open access transmission tariff design.
- Represented BC Hydro in RTO West market design process in areas of congestion management, ancillary services, and transmission pricing.

Energy and Climate Policy:

- Developed policy themes and integrated them into the four long-term planning scenarios under consideration by WECC's Scenario Planning Steering Group.
- Led a team that developed a model of deep carbon dioxide emissions reductions scenarios in the western United States and Canada on behalf of the State-Provincial Steering Committee, a body of western state and provincial officials that provides oversight for WECC.
- Led a study of likely changes to power flows and market prices at western electricity trading hubs following California's adoption of a cap-and-trade system for regulating greenhouse gas emissions in 2013.
- Served as advisor, facilitator and drafter to the Interim Committee in developing Idaho's first comprehensive, statewide energy plan in 25 years. The Interim Committee and subcommittees held 18 days of public meetings and received input from dozens of members of the public in developing state-level energy policy recommendations. This process culminated in Mr. Olson drafting the 2007 Idaho Energy Plan, which was approved by the Legislature and adopted as the official state energy plan in March 2007.
- Developed a model that forecasted renewable and conventional generating resources in the WECC region in 2020 as part of an E3 project to advise the California Public Utilities Commission, California Energy Commission and California Air Resources Board about the cost and feasibility of reducing greenhouse gas emissions in the electricity and natural gas sectors.

WASHINGTON OFFICE OF TRADE AND ECONOMIC DEVELOPMENT Olympia, WA
Senior Energy Policy Specialist 1996-2002

- **Electricity Transmission**: Lead responsibility for developing and representing agency policy interests in a variety of regional forums, with a primary focus on pricing and congestion management issues. Lead negotiator on behalf of agency in IndeGO and RTO West negotiations in areas of Congestion Management, Ancillary Services, and Transmission Planning. Participated in numerous subgroups developing issues including congestion zone definition, nature of long-term transmission rights, and RTO role in transmission grid expansion.

- **Western Regional Transmission Association, 1996-2001:** Member, WRTA Board of Directors. Participated in WRTA Tariff, Access and Pricing Committee. Participated in sub-groups examining "seams" issues among multiple independent system operators in the West and developing a proposal for tradable firm transmission rights in the Western interconnection.
- **Wholesale Energy Markets:** Monitored and analyzed trends in electricity, natural gas and petroleum markets. Editor and principal author of Convergence: Natural Gas and Electricity in Washington, a survey of the Northwest's natural gas industry in the wake of the extreme price events of winter 2000-2001, and on the eve of a significant increase in demand due to gas-fired power plants. Authored legislative testimony on the ability of the Northwest's natural gas industry to meet the demand from new, gas-fired power plants.
- **Electricity Restructuring:** Co-authored Washington Electricity System Study, legislatively-mandated study of Washington's electricity system in the context of ongoing trends and potential methods of electric industry restructuring. Authored legislative testimony on the impact of restructuring on retail electricity prices in Washington, electric industry restructuring and Washington's tax system, and the interactions between restructured electricity and natural gas markets.
- **Energy Data:** Managed three-person energy data team that collected and maintained a repository of state energy data. Developed Washington's Energy Indicators, a series of policy benchmarks and key trends for Washington's energy system; second edition published in January 2001.

DECISION ANALYSIS CORPORATION OF VIRGINIA Vienna, VA
Associate 1993-1996

- **Energy Modeling and Analysis:** Developed energy demand forecasting models for Energy Information Administration's National Energy Modeling System. Results are published each year in EIA's Annual Energy Outlook.

Education

University of Pennsylvania Philadelphia, PA
Institut de Francais du Petrole Rueil-Malmaison, France
M.S., International Energy Management & Policy

University of Washington Seattle, WA
B.S., Mathematical Sciences, B.S. Statistics

Citizenship

United States

Expert Witness Testimony

1. *Oregon Public Utilities Commission, 2017, testified on behalf of Commission staff regarding methodologies for assessing the value of customer-owned solar resources.*

2. *Oregon Public Utilities Commission, 2016, testified on behalf of Portland General Electric Company regarding methodologies for assessing the capacity contribution of variable renewable energy resources.*

3. *Province of Ontario, Commercial Arbitration, 2015, testified regarding policies related to renewable energy procurement and determination of available transmission capacity.*

4. *California Energy Commission, 2014, testified on behalf of Abengoa and BrightSource Energy regarding the cost and feasibility of distributed generation and energy storage alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

5. *California Energy Commission, 2013, testified on behalf of BrightSource Energy regarding the cost and feasibility of distributed generation alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

6. *Alberta Electric Utilities Commission, 2012, testified on behalf of Powerex Corporation reviewing industry practices regarding treatment of existing transmission capacity, in the case when new transmission lines are interconnected.*

7. *California Public Utilities Commission, 2011, provided testimony on behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company regarding cost, revenue requirement, average retail rates, and cost of carbon reductions from alternative resource portfolios in the Long-Term Procurement Planning Proceeding.*

8. *California Energy Commission, 2010, testified on behalf of BrightSource Energy regarding the cost and feasibility of distributed generation alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

Publications

1. *Woo, C.K., J. Zarnikau, Y. Chen, A. Olson, J. Moore, T. Ho, Y. Liu, and X. Luo (2017) “An empirical analysis of California’s hybrid capacity options” Electricity Journal, forthcoming*

2. *Woo, C.K., A. Olson, Y. Chen, J. Moore, N. Schlag, A. Ong, and T. Ho (2017) “Does California's CO2 price affect wholesale electricity prices in the Western U.S.A.?” Energy Policy, 110, 9–19*

3. *Olson, A., C.K. Woo, N. Schlag and A. Ong (2016) "What Happens in California Does Not Always Stay in California: The Effect of California's Cap-and-Trade Program on Wholesale Electricity Prices in the Western Interconnection," The Electricity Journal, 29(7), 18-22.*

4. *Woo, C.K., J. Moore, B. Schneiderman, T. Ho, A. Olson, L. Alagappan, K. Chawla, N. Toyama, J. Zarnikau (2016) "Merit-order effects of renewable energy and price divergence in California's day-ahead and real-time electricity markets," Energy Policy, 92, 299-312.*

5. *Woo, C.K., J. Moore, B. Schneiderman; A. Olson; R. Jones; T. Ho; N. Toyama; J. Wang; and J. Zarnikau, "Merit-order Effects of Day-ahead Wind Generation Forecast in the Hydro-rich Pacific Northwest", The Electricity Journal, Vol. 28, Issue 9, November 2015*

6. *Olson, A., A. Mahone, E. Hart, J. Hargreaves, R. Jones, N. Schlag, G. Kwok, N. Ryan, R. Orans and R. Frowd, "Halfway There: Can California Achieve a 50% Renewable Grid?", IEEE Power and Energy Magazine, Volume:13, Issue: 4, pp. 41-52, July-Aug. 2015*

7. *Olson, A., R. Jones, E. Hart and J. Hargreaves, "Renewable Curtailment as a Power System Flexibility Resource," The Electricity Journal, Volume 27, Issue 9, November 2014, pages 49-61*

8. *Hargreaves, J., E. Hart, R. Jones and A. Olson, "REFLEX: An Adapted Production Simulation Methodology for Flexible Capacity Planning," IEEE Transactions on Power Systems, Volume:30, Issue: 3, September 2014, pages 1306 - 1315*

9. *Woo, C.K., T. Hob, J. Zarnikau, A. Olson, R. Jones, M. Chait, I. Horowitz, J. Wang, "Electricity-market price and nuclear power plant shutdown: Evidence from California", Energy Policy,* 2014, vol. 73, issue C, pages 234-244

10. *Woo, C.K., Zarnikau J, Kadish J, Horowitz I, Wang J, Olson A. (2013) "The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest," IEEE Transactions on Power Systems, 28(4), 4245-4253.*

11. *Orans, R., A. Olson, J. Moore, J. Hargreaves, R. Jones, G. Kwok, F. Kahrl, and C.K. Woo (2013) "Energy Imbalance Market Benefits in the West: A Case Study of PacifiCorp and CAISO," Electricity Journal, 26:5, 26-36.*

12. *Olson A., R. Jones (2012) "Chasing Grid Parity: Understanding the Dynamic Value of Renewable Energy," Electricity Journal, 25:3, 17-27.*

13. *Woo, C.K., H. Liu, F. Kahrl, N. Schlag, J. Moore and A. Olson (2012) "Assessing the economic value of transmission in Alberta's restructured electricity market," Electricity Journal, 25(3): 68-80.*

14. *DeBenedictis, A., D. Miller, J. Moore, A. Olson, C.K. Woo (2011) "How Big is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest," Electricity Journal, 24:3, 72-76.*

15. *Woo, C.K., I. Horowitz, A. Olson, A. DeBenedictis, D. Miller and J. Moore (2011) "Cross-Hedging and Forward-Contract Pricing of Electricity in the Pacific Northwest," Managerial and Decision Economics, 32, 265-279.*

16. *Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*

17. *Olson A., R. Orans, D. Allen, J. Moore, and C.K. Woo (2009) "Renewable Portfolio Standards, Greenhouse Gas Reduction, and Long-line Transmission Investments in the WECC," Electricity Journal, 22:9, 38-46.*

18. *Moore, J., C.K. Woo, B. Horii, S. Price, A. Olson (2009) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*

19. *Woo, C.K., I. Horowitz, N. Toyama, A. Olson, A. Lai, and R. Wan (2007) "Fundamental Drivers of Electricity Prices in the Pacific Northwest," Advances in Quantitative Analysis of Finance and Accounting, 5, 299-323.*

20. *Lusztig, C., P. Feldberg, R. Orans, and A. Olson (2006) "A survey of transmission tariffs in North America," Energy-The International Journal 31, 1017-1039.*

21. *Woo, C.K., A. Olson, I. Horowitz and S. Luk (2006) "Bi-directional Causality in California's Electricity and Natural-Gas Markets," Energy Policy, 34, 2060-2070.*

22. *Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA, 34:1, 70-80.*

23. *Woo, C.K., A. Olson and I. Horowitz (2006) "Market Efficiency, Cross Hedging and Price Forecasts: California's Natural-Gas Markets," Energy, 31, 1290-1304.*

24. *Woo, C.K., A. Olson and R. Orans (2004) "Benchmarking the Price Reasonableness of an Electricity Tolling Agreement," Electricity Journal, 17:5, 65-75.*

25. *Orans, R., A. Olson, C. Opatrny, Market Power Mitigation and Energy Limited Resources, Electricity Journal, March, 2003.*

Selected Public Presentations

1. *"Customer Engagement: An Adaptive Survival Strategy for Electric Utilities", invited speaker, Energy NewsData Utility Customer Engagement Conference, Portland, Oregon, November 17, 2017*

2. *"Customer Engagement: What Does Success Look Like?", invited speaker, Energy NewsData Utility Customer Engagement Conference, Portland, Oregon, November 17, 2017*

3. *"Grid of the Future, Industry of the Future", Platinum Seminar at the Northwest and Intermountain Power Producer Coalition Annual Meeting, Union, Washington, September 11, 2017*

4. *"California's Solar Buildout: Implications for Electricity Markets in the West", invited speaker, EPIS Electric Market Forecasting Conference, Las Vegas, Nevada, September 7, 2017*

5. *"Value of Hydro in a GHG-Constrained World", invited panelist, HydroVision International, Session 1A: How Does Hydro 'Play' in the Energy Playground? Welcome to the New Wild West, Denver, Colorado, June 28, 2017*

6. *"Resource Adequacy and Planning Reserve Margins", invited speaker, Technical Conference on Capacity Planning and Resource Adequacy, Montana Public Service Commission, Helena, Montana, June 8, 2017*

7. *"That Faint Whooshing Sound: California Solar and Changing Western Power Markets", invited speaker, Northwest Power Markets: Mapping the Road Ahead, presented by Energy NewsData and CJB Energy, Portland, Oregon, May 24, 2017*

8. *"Observations on Current Resource Adequacy Practices", invited speaker, Committee for Regional Electric Power Cooperation/Western Interconnection Regional Advisory Body, Boise, Idaho, April 13, 2017*

9. *"Assessing Flexibility Needs in Highly Renewable Systems," invited speaker, Wärtsilä Symposium, Portland, Oregon, September 27, 2016*

10. *"Review: Natural Gas Infrastructure Adequacy in the Western Interconnection," invited speaker, Committee for Regional Electric Power Cooperation/Western Interconnection Regional Advisory Body, San Diego, California, October 31, 2016*

11. *"PATHWAYS to Deep Decarbonization: California", Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Salt Lake City, Utah, August 17, 2016*

12. *"Renewable Euphoria and the 'Big Long': How Renewable Energy Will Impact Western Markets", invited speaker, Mid-C Seminar, Wenatchee, Washington, July 27, 2016*

13. *"The Role of Renewables in Meeting California's Greenhouse Gas Goals", invited speaker, Renewable Energy Integration Summit, San Diego Regional Chamber of Commerce, July 18, 2016*

14. *"Essential Reliability Services", invited panelist, Western Electric Coordinating Council, Western Reliability Summit, Salt Lake City, Utah, May 18, 2016*

15. *"Meeting a 50% RPS for California", invited panelist, Infocast California Energy Summit, Santa Monica, California, May 11, 2016*

16. *"The Future of Resource Planning", invited keynote speaker, Great Plains Institute's e21 Initiative, St. Paul, Minnesota, April 5, 2016*

17. *"Market Driven Distributed Generation in the Western Interconnection", invited panelist, Committee on Regional Electric Power Cooperation biennial meeting, Salt Lake City, Utah, March 22, 2016*

18. *"Is Solar the New Hydro?", invited panelist, Northwest Hydroelectric Association 2016 Annual Conference, Portland, Oregon, February 17, 2016*

19. *"The Role of Energy Storage as a Renewable Integration Solution under a 50% RPS", invited panelist, Joint California Energy Commission and California Public Utilities Commission Long-Term Procurement Plan Workshop on Bulk Energy Storage, Sacramento, California, November 20, 2015*

20. *"Planning for Variable Generation Integration Needs", invited panelist, Utility Variable-generation Integration Group, Operating Impact And Integration Studies Users Group Meeting, San Diego, California, October 13, 2015*

21. *"The Role of Renewables in a Post-Coal World", invited panelist, Energy Foundation, Beyond Coal to Clean Energy Conference, San Francisco, California, October 9, 2015,*

22. *"Implications of a 50% RPS for California", invited panelist, Argus Carbon Summit, Napa, California, October 6, 2015*

23. *"Western EIM: Status Report and Implications for Public Power", Keynote speaker, Large Public Power Council meeting, Seattle, Washington, September 16, 2015*

24. *"California's 50% RPS Goal: Opportunities for Western Wind Developers", Keynote speaker at a meeting of the Wyoming Infrastructure Authority, Berkeley, California, July 28, 2015*

25. *"Western Interconnection Flexibility Assessment", Western Electric Coordinating Council Board of Directors, Salt Lake City, Utah, June 24, 2015*

26. *"California's New GHG Goals: Implications for the Western Electricity Grid", invited panelist, National Association of State Energy Officials, Western Regional State and Territory Energy Office Meeting, Portland, Oregon, May 14, 2015*

27. *"Replacing Aging Fossil Generation," invited panelist, Northwest Energy Coalition NW Clean & Affordable Energy Conference, Portland, Oregon, November 7, 2014*

28. *"Investing in Power System Flexibility," invited panelist, State/Provincial Steering Committee & Committee on Regional Electric Power Cooperation System Flexibility Forum, San Diego, California, October 20, 2014*

29. *"Opportunities and Challenges for Higher Renewable Penetration in California", invited panelist, Beyond 33%: University of California at Davis Policy Forum Series, Sacramento, California, October 17, 2014*

30. *"Renewable Curtailment as a Power System Flexibility Resource," Boise State University Energy Policy Research Conference, San Francisco, California, September 4, 2014*

31. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", Pacific Northwest Utilities Conference Committee Board of Directors, Portland, Oregon, August 8, 2014*

32. *"The Future of Renewables in the American West," invited panelist, Geothermal Energy Association Annual Meeting, Reno, Nevada, August 6, 2014*

33. *"Long-Term Natural Gas Infrastructure Needs", invited panelist, U.S. Department of Energy Quadrennial Energy Review, Public Meeting #7, Denver, Colorado, July 28, 2014*

34. *"Meeting the Demands of Renewables Integration—New Needs, New Technologies, Emerging Opportunities", invited panelist, InfoCast 2nd Annual California Energy Summit, San Francisco, California, May 28, 2014*

35. *"Power System Flexibility Needs under High Renewables", EUCI Utility Resource Planning Conference, Chicago, Illinois, May 14, 2014*

36. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", Western Interstate Energy Board Annual Meeting, Denver, Colorado, April 24, 2014*

37. *"Power System Flexibility Needs under High RPS", invited panelist, joint meeting of the Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Tempe, Arizona, March 26, 2014*

38. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", joint meeting of the Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Tempe, Arizona, March 25, 2014*

39. *"Investigating a Higher Renewables Portfolio Standard for California", 19th Annual Power Conference on Energy Research and Policy, University of California Energy Institute, Berkeley, California, March 17, 2014*

40. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited panelist, Northwest Power and Conservation Council, Portland, Oregon, March 12, 2014*

41. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited panelist, Western Systems Power Pool, Spring Operating Committee Meeting, Whistler, B.C., March 5, 2014*

42. *"Investigating a Higher Renewables Portfolio Standard for California", invited speaker, Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Salt Lake City, Utah, February 25, 2014*

43. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited speaker, Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Webinar, February 12, 2014*

44. *"Flexibility Planning: Lessons From E3's REFLEX Model", EUCI Conference on Fast Ramp and Intra-Hour Market Incentives, San Francisco, California, January 29-30, 2014*

45. *"The Effect of High Renewable Penetration on California Markets and Carbon Balance", EUCI Conference on California Carbon Policy Impacts on Western Power Markets, January 27-28, San Francisco, California, 2014*

46. *"Reliance on Renewables: A California Perspective", invited panelist at Harvard Electricity Policy Group, Seventy-Third Plenary Session, Tucson, Arizona, December 13, 2013*

47. *"The Role of Renewables in Meeting Long-Term Greenhouse Gas Reduction Goals", State Bar Of California, Energy And Climate Change Conference, Berkeley, California, November 14, 2013*

48. *"Benefits, Costs and Cost Shifts from Net Energy Metering", invited expert panelist at Washington Utilities and Transportation Commission Workshop on Distributed Generation, Olympia, Washington, November 13, 2013*

49. *Pacific Northwest Utilities Conference Committee (PNUCC) California Power Industry Roundtable, invited panelist, Portland, Oregon, September 6, 2013*

50. *"After 2020: Prospects for Higher RPS Levels in California", invited speaker at Northwest Power and Conservation Council's California Power Markets Symposium, Portland, Oregon, September 5, 2013*

51. *"Determining Flexible Capacity Needs for the CAISO Area", invited speaker at Northwest Power and Conservation Council's California Power Markets Symposium, Portland, Oregon, September 5, 2013*

52. *"California Climate Policy and the Western Energy System", invited speaker at the Western Interstate Energy Board annual meeting, Reno, Nevada, June 13, 2013*

53. *"Determining Power System Flexibility Need", EUCI Conference on Resource Planning and Asset Valuation, Westminster, Colorado, May 21, 2013*

54. *"California Policy Landscape and Impact on Electricity Markets", EUCI Conference on Resource Planning and Asset Valuation, Westminster, Colorado, May 21, 2013*

55. *"Determining Power System Flexibility Need", EUCI Conference on Fast and Flexi-ramp Resources, Chicago, Illinois, April 23, 2013*

56. *"State-Provincial Steering Committee WECC Low Carbon Scenarios Tool", 3 Interconnections Meeting, Washington, DC, February 6, 2013*

57. *"Distributed Generation Benefits and Planning Challenges", Committee on Regional Electric Power Cooperation/State-Provincial Steering Committee, Resource Planners' Forum, San Diego, California, October 3, 2012*

58. *"Thoughts on the Flexibility Procurement Modeling Challenge", invited speaker at the California Public Utilities Commission, Long-Term Procurement Planning Workshop, San Francisco, California, September 19, 2012*

59. *"Generation Capital Cost Recommendations for WECC 10- and 20-Year Studies", Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Technical Advisory Subcommittee, Webinar, August 15, 2012*

60. *"Renewable Energy Benefits", California Energy Commission, Integrated Energy Policy Report Workshop, Sacramento, California, April 12, 2012*

61. *"The Role of Policy in WECC Scenario Planning", Western Electric Coordinating Council, Scenario Planning Steering Group, San Diego, CA, November 1, 2011*

62. *"WECC Energy Imbalance Market Benefit Study", Western Electric Coordinating Council, Board of Directors, Scottsdale, Arizona, June 22, 2011*

63. *"Renewable Portfolio Standard Model Methodology and Draft Results", California Public Utilities Commission Workshop, San Francisco, California, June 17, 2010*

64. *"Draft Results from 33% Renewable Energy Standard Economic Modeling", California Air Resources Board Workshop, Sacramento, California, May 20, 2010*

65. *"Market Opportunities for IPPs in the WECC", invited speaker at the Independent Power Producers of British Columbia Annual Meeting, Vancouver, British Columbia, November 2, 2009*

66. *"A Low-Transmission Alternative for Meeting California's 33% RPS Target", EUCI Webinar, July 31, 2009*

67. *"Remote Renewable and Low-Carbon Resource Options for the Pacific Northwest", Center for Research on Regulated Industries Conference, Monterey, California, June 19, 2009*

68. *"Engineers are from Mars, Policy-Makers are from Venus: The Effect of Policy on Long-Term Transmission Planning", invited speaker at the Western Electric Coordinating Council Long Term Transmission Planning Seminar, Phoenix, Arizona, February 2, 2009*

69. *"The Long-Term Path to a Stable Climate, and its Implications for BPA", invited speaker at the Bonneville Power Administration Managers' Retreat, Portland, Oregon, April 29, 2008*

70. *"Load-Resource Balance in the Western Interconnection: Towards 2020", Western Electric Industry Leaders Group, Las Vegas, Nevada, January 18, 2008*

71. *"Integrated Resource Planning for BPA Customers", invited speaker at the Bonneville Power Administration Allocation Conference, Portland, Oregon, September 19, 2006*

72. *"Idaho's Current Energy Picture", Energy, Environment and Technology Interim Committee, Boise, Idaho, July 11, 2006*

73. *"Locational Marginal Pricing – The Very Basics", Committee on Regional Electric Power Cooperation, San Diego, California, April 30, 2002*

74. *"Effect of 2000-2001 Energy Crisis on Washington's Economy", Conference on Business Economics, Seattle, Washington, July 19, 2001*

Research Reports

1. *Investigating the Economic Value of Flexible Solar Power Plants, October 2018, prepared on behalf of First Solar with the assistance of Tampa Electric Company, project lead and contributing author,* https://www.ethree.com/projects/investigating-the-economic-value-of-flexible-solar-plants/

2. *Pacific Northwest Low Carbon Scenario Analysis, December 2017, prepared on behalf of the Public Generating Pool, project lead and contributing author,* https://www.ethree.com/projects/study-policies-decarbonize-electric-sector-northwest-public-generating-pool-2017-present/

3. *Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, July 2016, prepared on behalf of the California Independent System Operator, project lead and contributing author,* https://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx

4. *Western Interconnection Flexibility Assessment, December 2015, prepared on behalf of the Western Electric Coordinating Council and the Western Interstate Energy Board, project lead and contributing author,* https://ethree.com/public_projects/western_interconnection_study.php

5. *Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric Sector Perspective, July 2014, prepared on behalf of the Western Interstate Energy Board, project lead and contributing author,* https://ethree.com/public_projects/wieb.php

6. *Investigating a Higher Renewables Portfolio Standard for California, January 2014, prepared on behalf of the Los Angeles Department of Water and Power, Pacific Gas and Electric Company, Sacramento Municipal Utilities District, San Diego Gas & Electric, and Southern California Edison, technical lead and lead author,* http://www.ethree.com/public_projects/renewables_portfolio_standard.php

7. *Optimal Investment in Power System Flexibility, E3 White Paper, December 2013,* https://ethree.com/documents/Olson_Flexibility_Investment_2013-12-23.pdf

8. *Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process, October 2012, prepared on behalf of the Western Electric Coordinating Council, editor and contributing author,* http://www.wecc.biz/committees/BOD/TEPPC/TAS/121012/Lists/Minutes/1/121005_GenCapCostReport_finaldraft.pdf.

9. *Economic Assessment of North/South Transmission Capacity Expansion in Alberta, January 2012, prepared on behalf of AltaLink, contributing author.*

10. *WECC EDT, Phase 2 EIM Benefits, Analysis & Results, October 2011, prepared on behalf of the Western Electric Coordinating Council, contributing author,* *http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf*

11. *High Plains Express Initiative, Stage 2 Feasibility Report, April 2011, contributing author,* *http://www.highplainsexpress.com/site/stakeholderMeetingDocuments/HPX_Stage-2_Feasibility-report.pdf*

12. *State of Wyoming Wind Energy Costing Model, June 2010, prepared on behalf of the Wyoming Infrastructure Authority and Governor's office, author,* *http://legisweb.state.wy.us/2010/WyomingWindModel_7_01_2010.pdf*

13. *Recommendations for Documentation of Seattle City Light Energy Delivery Capital Expenditures, February 2010, prepared on behalf of the Seattle City Council, contributing author,* *http://clerk.seattle.gov/~ordpics/31219exA.pdf*

14. *California Public Utilities Commission, 33% Renewables Portfolio Standard Implementation Analysis, Preliminary Results, June 2009, contributing author,* *http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf*

15. *California Public Utilities Commission, Energy Division Straw Proposal on LTPP Planning Standards, June 2009, contributing author,* *http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf*

16. *California Public Utilities Commission, Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California, September 2008,* *http://www.cpuc.ca.gov/NR/rdonlyres/029611EA-D7C7-4ACC-84D6-D6BA8515723A/0/ConsultantsReportonUtilityPlanningPracticesandAppendices09172008.pdf.*

17. *Remote Renewable and Low-Carbon Resource Options for BPA, May 2008, prepared on behalf of the Bonneville Power Administration, author,* *http://www.ethree.com/public_projects/BPA_options.html*

18. *Load-Resource Balance in the Western Interconnection: Towards 2020, prepared on behalf of the Western Electric Industry Leaders Group, January 2008, contributing author,* *http://www.weilgroup.org/E3_WEIL_Complete_Study_2008_082508.pdf*

19. *Umatilla Electric Cooperative 2008 Integrated Resource Plan, January 2009, contributing author.*

20. *Lower Valley Energy 2007 Integrated Resource Plan Update, February 2007, contributing author.*

21. *Idaho Legislative Council Interim Committee on Energy and Technology and Energy and Environmental Economics, Inc., 2007 Idaho Energy Plan, January 2007.* *http://www.legislature.idaho.gov/sessioninfo/2007/energy_plan_0126.pdf*

22. *Base Case Integrated Resource Plan for PNGC Power, April 2006, author.*

23. *Integrated Resource Planning for Coos-Curry Electric Cooperative, August 2005, author.*

24. *Integrated Resource Planning for Lower Valley Energy, December 2004, author.*

25. *"A Forecast Of Cost Effectiveness: Avoided Costs and Externality Adders", prepared for the California Public Utilities Commission, February 2004, contributing author.*

26. *Stepped Rate Design Report, prepared for BC Hydro and filed with the BCUC, May 2003, contributing author.*

27. *Convergence: Natural Gas and Electricity in Washington, editor and principal author. Washington Office of Trade and Economic Development, May 2001.* *http://www.energy.cted.wa.gov/Papers/Convergence.htm*

28. *2001 Biennial Energy Report: Issues and Analyses for the Washington State Legislature, contributing author. Washington Office of Trade and Economic Development, February 2001.* *http://www.energy.cted.wa.gov/BR2001/default.htm*

29. *Study of Electricity Taxation, contributing author. Washington Department of Revenue, December 1999.* *http://www.energy.cted.wa.gov/papers/taxstudy.doc*

30. *Washington Energy Indicators, author. Washington Department of Community, Trade and Economic Development, February, 1999.* *http://www.energy.cted.wa.gov/Indicators99/Contents.htm*

31. *Washington State Electricity Study, contributing author. Washington Department of Community, Trade and Economic Development and Washington Utilities and Transportation Commission, January 1999.* *http://www.energy.cted.wa.gov/6560/finalapp.htm*

32. *Our Energy Future: At a Crossroads. 1997 Biennial Energy Report, contributing author. Washington Department of Community, Trade and Economic Development, January 1997.* *http://www.energy.cted.wa.gov/BIENREPO/CONTENTS.HTM*

33. *Washington State Energy Use Profile 1996, contributing author. Washington State Energy Office, June, 1996.* *http://www.energy.cted.wa.gov/FILES/PRFL/BASE02.HTM*

34. *Model Documentation Report: Transportation Sector Model of the National Energy Modeling System, contributing author. Decision Analysis Corporation of Virginia. Prepared for Energy Information Administration, March 1994.*

**DIRECT TESTIMONY OF ARNE OLSON
ON BEHALF OF
THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE**

EXHIBIT AO-2

Review of Duke's 2020 Integrated Resource Plan

Prepared for Cypress Creek Renewables

January 2021

Energy+Environmental Economics

Review of Duke's 2020 Integrated Resource Plan

January 2021

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
415.391.5100
www.ethree.com

Project Team:
Arne Olson
Zachary Ming
Stuart Mueller
Louis Linden
Robbie Shaw

Table of Contents

Acronyms

DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
ELCC	Effective Load Carrying Capability
ICAP	Installed Capacity
IRP	Integrated Resource Planning
LOLE	Loss of Load Expectation
PRM	Planning Reserve Margin
RECAP	Renewable Energy Capacity Planning Model
UCAP	Unforced Capacity

1 Executive Summary

This report was prepared by Energy and Environmental Economics, Inc. (E3) on behalf of Cypress Creek Renewables (CCR) and for use by the Carolinas Clean Energy Business Association (CCEBA) as a technical review of the 2020 Duke integrated resource plan (IRP). Although we address a larger number of topics in this report, our primary focus is on the capacity expansion methodology used by Duke and the ELCC values that were generated by Astrapé in its accompanying 2018 Solar Capacity Value Study.

Electric resource planning is the process of identifying longer-term investments to meet reliability and public policy objectives at the least cost.[1] Historically, IRP processes focused on the balance of dispatchable generation technologies that would meet baseload, seasonal and peaking requirements in a least-cost manner. The evolution of generation technologies and storage options in parallel with developing policy obligations has increased the complexity of IRP processes across North America and around the world. The 2020 Duke IRP is effective at addressing some of these challenges but falls short of best practice on others. This report will outline these areas and provide two primary recommendations for improvement.

Capacity Expansion Modeling Review

The capacity expansion stage of an IRP is the focal point of balancing resource cost, policy and reliability to ensure a least-cost resource plan. It is this modeling stage in which all existing and future resource mix

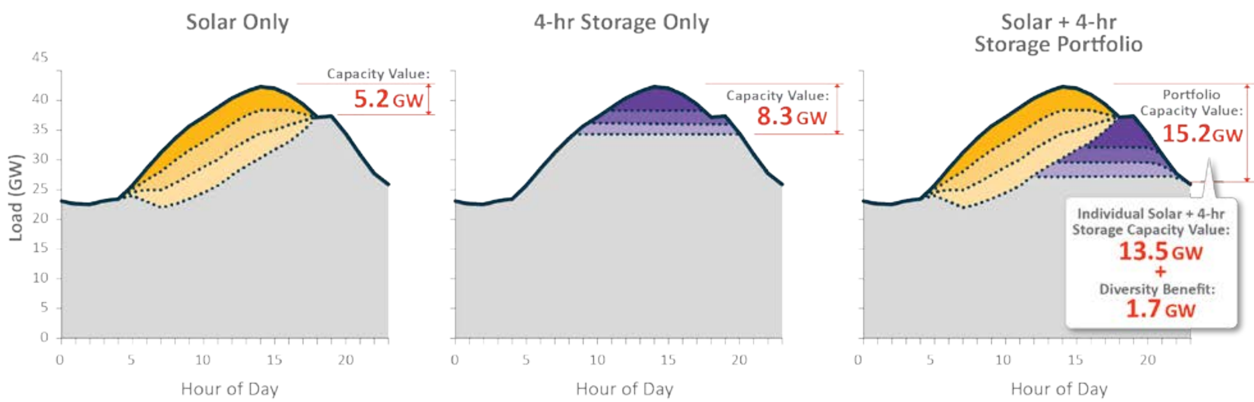
[1] Kahrl, Fredrich, Andrew Mills, Luke Lavin, Nancy Ryan and Arne Olson, *The Future of Electricity Resource Planning*, Report No. 6 of Lawrence Berkeley National Laboratory's series The Future of Electricity Regulation, September 2016

possibilities are investigated, constrained by policy, and a least-cost solution to meet reliability requirements and policy goals is achieved.

The Duke IRP uses a multi-step methodology for its capacity expansion in which battery storage is evaluated as a replacement option for combustion turbine generation based on a side-by-side comparison with the rest of the portfolio held constant. While this method can produce acceptable results for two resources with somewhat similar characteristics, it ignores the synergistic effects that exist between storage and other resources such as solar. When solar generation and battery storage are considered in tandem, their combined capacity contribution is greater than if the two resources are considered separately – i.e., the whole is greater than the sum of the parts. Duke's methodology fails to account for those combined benefits.

This phenomenon is illustrated in Figure 1, which shows an example in which solar alone has an effective capacity of 5.2 GW and storage alone contributes 8.3 GW. However, because batteries can soak up solar energy and use it for energy production at night, and because the presence of solar energy narrows the net peak, making it easier to serve with short duration batteries, the combined capacity contribution is 15.2 GW, 1.7 GW higher than the sum of standalone solar and standalone storage.

Figure 1: Illustration of the Synergistic Effects of Solar and Storage



Duke's capacity expansion methodology considers solar and storage independently, at different steps of the process, ignoring these synergistic benefits. As a result, the Duke IRP likely fails to identify a least-cost solution for its ratepayers.

Effective Load Carrying Capability Review

A key input to the capacity expansion modeling phase on an IRP process is the assumed capacity contribution from each resource type. Duke should be commended for its use of Effective Load Carrying Capability (ELCC) metrics to determine the capacity credit for renewables and energy storage, in keeping with industry best practice. However, E3's review of the 2018 Astrapé Solar Capacity Value study reveals a number of implementation details that, taken together, appear to significantly and unreasonably diminish the capacity value of solar. Specifically, these are:

1. Duke improperly assumes that dispatchable resources do not suffer forced outages in its capacity expansion modeling, disadvantaging renewable resources.

2. The ELCC values of solar and storage are not dynamic with load growth on the system. As peak load grows, the ability of solar and battery storage to contribute also increases, which should be reflected in Duke's modeling.
3. Duke's use of outdated demand response assumptions reduces the capacity value of solar due to seasonal effects. The assumptions from Duke's Winter Demand Peak Reduction Potential Assessment should be used instead.
4. Duke's modeling of storage in "economic arbitrage" mode rather than "preserve reliability" mode diminishes the reliability value of both storage and solar.
5. Duke's assumption of fixed-tilt solar instead of tracking diminishes the capacity value of solar. Currently, nearly all the utility scale solar being built in the US is tracking solar which has improved ELCCs due to its ability to track the sun.

Recommendations

The review of both the capacity expansion and the ELCC methodologies has revealed several assumptions and processes that are not aligned with a best-in-class IRP that delivers a reliable plan at least-cost while respecting policy constraints.

E3 provides the following recommendations:

+ Duke should adopt a single-step capacity expansion modeling methodology that co-optimizes all resources and policy constraints simultaneously. This is the only way to ensure that the synergistic properties of solar and storage be represented, and a true least-cost solution can be found.
+ Duke should correct its assumption that dispatchable resource do not suffer from forced outages by utilizing an unforced capacity (UCAP) planning reserve margin in capacity expansion modeling.
+ Duke should update its 2018 Solar Capacity Value Study to:
    - Include updated demand response assumptions,
    - Express ELCC values as a function of peak demand, rather than as static values,

- Model storage resources in “preserve reliability” mode rather than “economic arbitrage” mode in SERVM, and
- Assume all new utility scale solar to be built in the future uses single-axis tracking.

2 Overview

2.1 Purpose of Report

E3 was retained to perform a technical review of Duke Energy's integrated resource plan ("IRP"). The review focused on two primary areas: 1) the methodology used by Duke to develop optimal portfolios via capacity expansion modeling, and 2) the effective load carrying capability ("ELCC") results calculated by Astrapé Consulting to value the capacity contribution of solar and storage resources in the Duke portfolio. This report provides several recommendations to improve the overall optimal portfolio development methodology employed by Duke to align it with best practices in evaluating high renewable electricity systems. In addition, this report contains a detailed review of the methodology and input assumptions used in Astrapé Consulting's solar ELCC study. Finally, to quantify the impact of several of E3's modeling recommendations, E3 has used its own loss-of-load-probability model (RECAP) to calculate updated ELCC values for both solar and storage and compared them to the values in the Astrapé study.

2.2 Overview of E3

E3 is a leading economic consultancy focused on the energy industry, with an emphasis on electricity and the clean energy transition. For over 30 years, E3 has served as an independent, data-driven technical consultant that diverse stakeholders can trust to provide fair and unbiased analysis and strategic guidance. Over the last 15 years, E3 has engaged extensively in IRP processes across North America, working to develop future portfolios that balance cost, environmental objectives, reliability, and equity. E3 provides advisory services and energy systems modeling to investor-owned utilities, public power agencies, project developers, regulators, grid operators, government agencies, and public interest advocacy groups across North America.

2.3 Report Contents

The remainder of this report is organized as follows:

- Section 3 provides an overview of IRP best practices and an assessment of Duke's approach focusing on resource adequacy;
- Section 4 provides a critique of the solar and storage ELCC studies from Astrapé Consulting and alternative ELCC results from E3 that rectify several issues; and
- Section 5 synthesizes all key findings with recommendations and actions that Duke could take to improve their IRP.

Additional detail on methods, inputs, and assumptions are summarized in the appendices attached to this report.

3 Integrated Resource Planning Review

3.1 Introduction

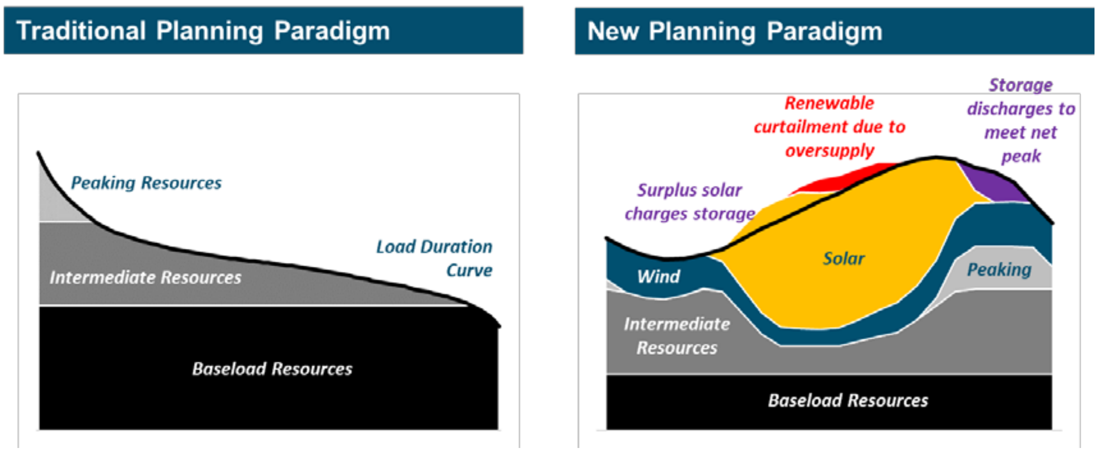
This section provides an overview of best practices in the execution of deeply decarbonized and high renewable IRPs with a special emphasis on capacity expansion modeling and optimization. It then reviews Duke's IRP in the context of these best practices. Finally, this section provides several recommendations for improvements to Duke's IRP and an evaluation of the impact these improvements would have.

3.2 IRP Best Practices

Integrated resource planning (IRP) is a long-established practice in the utility industry to evaluate different supply and demand measures while balancing multiple criteria including cost, reliability, the environment, and equity. Most models and evaluation processes used to perform this analysis were developed during an era when the generation technologies available to utility planners were much more limited than the options available today. Decisions often centered around which type of natural gas generator to invest in or whether a new coal or nuclear baseload unit was required.

The objectives of IRP today have evolved from years past and seek to not only minimize cost but also to meet emission reduction or renewable energy goals. Additionally, the types of resources available to planners have expanded greatly. Heuristics that used to provide a reasonable proxy within planning models no longer capture the economic, operational, and reliability complexities of today's resources. IRP must evolve to capture the uniqueness of these resources in order to credibly produce least-cost plans that satisfy both environmental and reliability criteria.

Figure 2: Depiction of Changing Resource Planning Paradigms



As the goals and tools available to integrated resource planners have evolved in recent years, best practices for IRP need to evolve as well. The traditional technologies used in electricity generation (dispatchable coal and natural gas generators) were simply matched with baseload, seasonal and peak load using fixed and variable cost. More recently, significant changes with respect to both policy and available generation technologies have necessitated the evolution of IRP processes. Specific examples of recent ongoing changes in the electricity sector include:

+ Reduction in cost of alternative energy resources including wind, solar, and energy storage;
+ Increasingly stringent policy goals to limit carbon emissions or increase renewable generation;
+ Customer demand for more control over their energy decisions; and
+ Technological advances in telemetry and metering that enable customers to engage more directly with their energy use.

Taking these new factors into account, a best-in-class IRP today must incorporate all of the following practices in order to ensure that the result is reliable and complies with policy requirements while identifying a least-cost portfolio for ratepayers:

1. Incorporate climate policy and the impacts of climate change

Climate change is affecting electric utilities in a variety of ways that can no longer be ignored. There are at least three ways in which climate change should be incorporated into integrated resource planning:

- **Physical risks:** Climate change is affecting the magnitude and duration of peak load events in increasingly measurable ways. IRPs should explicitly consider climate-induced changes in hourly load shapes, particularly during extreme hot or cold weather events. IRPs should also consider other physical risks such as higher forced outage rates and the potential for degrading asset performance due to higher winds during storm events, sea level rise, and others.

- **Direct carbon policy risks.** Climate policy will increasingly favor lower-emitting generating resources such as wind, solar, or nuclear relative to higher emitting resources such as coal or natural gas. Every utility in North America that owns or plans to own fossil resources faces significant regulatory risk related to GHG emissions that must be considered through an IRP process.

- **Higher electric loads.** Climate policy is already resulting in changes in electric load due to proliferation of electric vehicles, heat pumps, and other electrified technologies in many jurisdictions. Utility IRPs should include an assessment of the potential size, likelihood and timing of new sources of electric load.

2. Include renewable and energy storage resources as candidate resources

The capacity expansion stage of an IRP is the focal point of balancing resource cost, policy and reliability to ensure a least-cost resource plan. It is this modeling stage in which all existing and future resource mix possibilities are investigated, constrained by policy, and a least-cost solution to meet reliability requirements is achieved. IRPs should utilize a single-step capacity expansion modeling methodology that co-optimizes all resources and policy constraints simultaneously. This is the only way to ensure that the synergistic properties of renewables, energy storage and customer resources can be accurately quantified, and a true least-cost solution can be found.

- **Diversity benefits or synergistic effects.** Renewable and storage resources must be modeled in a way that incorporates storage's ability to shift non-dispatchable renewable energy to later in the day, not just simply accounting for the contribution of each resource individually.

- **Variability and weather correlations.** Load and generation profiles should capture meaningful fluctuations in the output of load, wind, and solar as well as correlations among them, to accurately capture renewable integration costs and anti-correlations between renewable output and peak load.

- **Operating reserves.** Portfolio modeling should consider the increased need for operating reserves and grid flexibility associated with higher penetrations of renewable resources.

- **Capacity contribution.** Portfolio modeling must capture synergistic dynamic interactions among and between renewable resources and storage with respect to their contribution toward meeting capacity needs.

3. Capacity need should be determined through robust loss of load probability (LOLP) modeling

Resource adequacy is an increasingly important topic as retirement of older, high-emitting resources accelerates and implementation of variable resources increases. Industry best practice related to resource adequacy includes:

- **Planning Reserve Margin established through Loss-of-Load Probability Modeling.** Robust LOLP modeling should be used to establish capacity needs based on a reliability standard of 1-day-in-10-years. The total need, which considers loads and resources during all hours of the year, can be translated into a Planning Reserve Margin (PRM) by dividing by the median peak load forecast and subtracting one.

- **Use of UCAP or PCAP for dispatchable resources.** Unforced capacity (UCAP) or perfect capacity (PCAP) should be used in PRM accounting. This ensures that the capacity accreditation of both dispatchable resources includes forced outage conditions that diminish performance during potential loss-of-load events.

- **Use of ELCC for dispatch-limited resources.** The capacity contribution of dispatch-limited resources such as solar, wind, energy storage and demand response should be evaluated using the Effective Load-Carrying Capability (ELCC) approach to accurately characterize their contribution toward reducing the frequency of loss-of-load events.

- **ELCC should capture interactive effects.** The LOLP modeling and ELCC calculations should capture both synergistic and antagonistic interactive effects of dispatch-limited resources.

4. IRP should consider the total resource cost (TRC) benefits that can be provided by demand side resources

There is increasing interest in distributed energy resources (DERs) due to technology improvement and electric customer's desires to control their energy bills. DERs offer advantages relative to supply-side resources due to their co-location with electric load, including reduced system losses, the potential to defer transmission or distribution system investments, and the ability to provide other services such as voltage control. At the same time, DERs may involve increased operational complexity and may require special arrangements to enable optimal dispatch based on system needs. Moreover, if compensation for DER services deviates from the utility's avoided costs, cost shifting may occur between customers with and without DERs. In order to accurately capture both the benefits and the complexities of incorporating increased DER penetration, IPRs should:

- **Consider the potential benefits of DERs using a Total Resource Cost perspective.** IRPs should consider potential benefits of customer resources including energy efficiency, demand response, and flexible loads using a Total Resource Cost (TRC) perspective that maximizes total ratepayer benefits.

- **Capture all benefits of DERs.** IRPs should capture all benefits from demand side resources including avoided transmission and distribution (T&D) infrastructure as well as avoided T&D energy losses in addition to avoided energy and capacity benefits.

- **Capture synergistic effects of DERs.** To the extent that DER penetration creates synergistic benefits with other resources such as customer storage and solar, DER penetration should be optimized alongside supply-side resources to ensure that the IRP identifies an optimal portfolio that maximizes ratepayer benefits. To the extent that synergistic effects are small, practical considerations may suggest that DERs be evaluated in a separate proceeding using an avoided cost methodology.

5. Operational flexibility needs should be addressed in a detailed operational study

Ensuring sufficient operational flexibility is an increasing source of concern for system planners as penetration of variable resources increases. Integration of variable resources requires increased levels of operating reserves to deal with variability and uncertainty, along with flexible resource to provide these services. At the same time, the value of flexibility is not infinite, and variable resources can themselves be a source of operational flexibility.[2] Operational flexibility is an important topic that should be considered in a detailed study of system operations.

- **Operational study should include operating reserves.** The operational study should include a detailed representation of operating reserve needs, which will likely increase as generation uncertainty from renewables compounds on historical load uncertainty and contingency requirements. The operating reserve needs should be calculated using advanced statistical measures that capture the full range of diversity among load, wind, and solar resources at different locations across the system.

- **Operational study should utilize time-series production simulation modeling.** Time-series modeling includes the impact of commitment decisions that must be made in advance, e.g., day-ahead, utilizing imperfect information about real-time dispatch conditions as well as an assessment of the headroom and footroom that would be required to accommodate real-time output variability.

6. Robust, transparent, stakeholder process

Given the increasing public policy-based interest in energy resources, a utility IRP should include a robust, transparent stakeholder process.

- **Process should seek out diverse perspectives.** IRP should incorporate opportunities for a diverse array of stakeholders to be meaningfully involved in the conception, execution, interpretation, and outcomes of the IRP process.

[2] Energy and Environmental Economics, Inc., *investigating the Economic Value of Flexible Solar Power Plant Operation*, October 2018, https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf

- **Process should include multiple rounds of stakeholder comment.** Stakeholders should be given an opportunity to comment on modeling methodologies, data inputs, draft results, and final results.

While E3 is not aware of any utility that is currently adhering to all of the six components of a best-in-class IRP listed above, we are aware of a number that incorporate components into their process.

+ Nova Scotia Power IRP uses a UCAP PRM with ELCC curves in capacity expansion modeling as well as a robust stakeholder engagement process.
+ Public Service Company of New Mexico (PNM) uses a capacity expansion model that co-optimizes solar and storage using ELCC curves in addition to a stakeholder process, climate change policy objectives, and a UCAP PRM accounting convention.
+ CPUC IRP captures declining solar and storage capacity contributions and incorporates the climate policy and the impacts of climate change.

3.3 Specific Subjects for E3's Review of Duke's IRP

E3's scope of work was limited to reviewing select aspects of the Duke IRP, namely the ELCC of solar and storage resources as well as the methodology to develop optimal portfolios. The following sections provide greater detail on IRP best practices for these two components and a contrast with the approaches used by Duke. E3 was not retained to evaluate the Duke IRP on any other criteria and as such information regarding additional topics is not included in this report.

3.3.1 RELIABILITY PLANNING

Central to integrated resource planning is ensuring that the electric system is reliable for its customers. The standard approach to ensuring reliability is to establish the quantity of generating capacity needed to ensure a given reliability level, usually targeted to be one outage every ten years. This quantity of capacity is characterized through a planning reserve margin (PRM) that specifies the level of generating capacity required in excess of peak demand.

There are two types of PRM accounting: (1) installed capacity PRM ("ICAP PRM") defined as the level of nameplate capacity needed to meet a reliability level and (2) unforced capacity PRM ("UCAP PRM") which defines the amount of de-rated capacity – nameplate capacity that has been reduced to account for outages – required to meet a reliability level.[3] ICAP or UCAP PRM are simply accounting conventions, so each can accurately quantify the required reserve margin to meet a reliability threshold. However, a UCAP PRM that accounts for the requirement in terms of de-rated capacity is more straightforward to use when the system has growing levels of renewable generation and energy storage.

In the past, PRM accounting (ICAP or UCAP) has been relatively simple because most generating capacity has been "firm" – available at full capacity except in the unplanned outages. However, with the unprecedented growth of non-firm capacity, namely renewables, the nature of reliability is changing. As the level of renewables increases, reliability challenges will be driven more and more by lack of wind or sun as opposed to peak load hours. As discussed in Section 4.1.1, below, using UCAP rather than ICAP ensures that non-firm capacity and firm capacity are compared on a level playing field.

A wide range of approaches and conventions has been used to incorporate these "non-firm" resources into resource adequacy programs. Increasingly, the industry has turned to effective load carrying capability (ELCC) as the preferred method for measuring the resource adequacy contribution of intermittent or dispatch-limited resources. ELCC, typically denoted in MW, is defined as the equivalent amount of "perfect capacity" that could be replaced with a specified resource while maintaining the same

[3] For example, a system which requires 1,150 MW of installed firm capacity serving a peak load of 1,000 MW represents an ICAP PRM of 150 MW or 15%. Assuming a forced outage rate of 5%, this same system's UCAP PRM would be 1,150 MW x (1 – 5%) – 1,000 MW = 93 MW or 9.3%. Whether measured using ICAP or UCAP, the system has the same reliability level and the same capacity need.

level of reliability. ELCC is derived directly from the loss-of-load probability modeling that system planners have long utilized to determine the PRM.

The ELCC of a resource depends not only on the characteristics of load in a specific area (i.e. how coincident its production is with load) but also upon the resource mix of the existing system (i.e. how it interacts with other resources). For instance, ELCCs for variable renewable resources are generally found to be higher on systems with large amounts of inherent storage capability (e.g. large hydro systems) than on systems that rely predominantly on thermal resources and have limited storage capability. ELCCs for a specific type of resource are also a function of the penetration of that resource type; in general, most resources exhibit declining capacity value with increasing scale. This is generally a result of the fact that continued addition of a single resource or technology will lead to saturation when that resource is available and will shift reliability events towards periods when that resource is not available. The diminishing impact of increasing solar generation as the net peak shifts to the evening illustrates this effect. This effect is further described in Section 3.3.2 outlining the interaction between the nature and shape of demand on a system and the ability of resources to meet them.

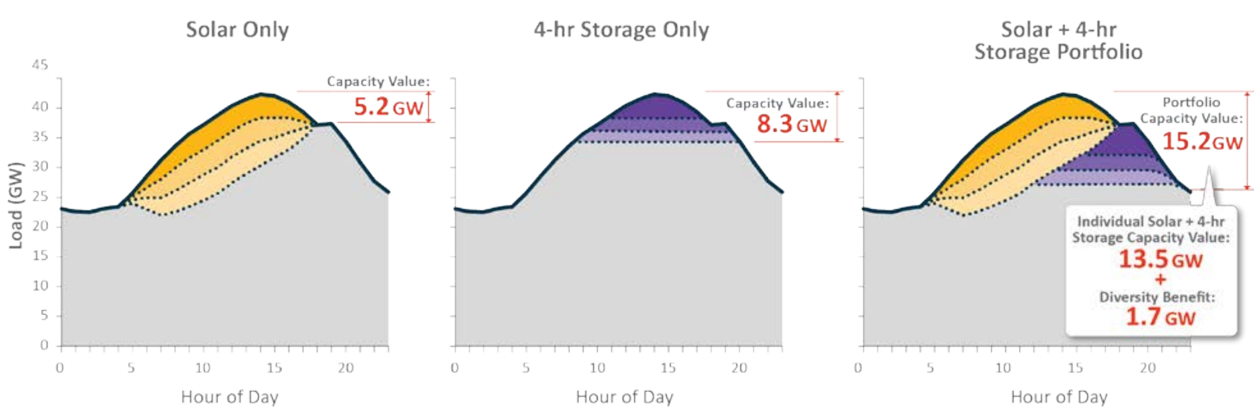
3.3.2 CAPACITY EXPANSION MODELING

Using a reliability metric (whether it is ICAP or UCAP), the IRP process focuses on ensuring that enough generation capacity is available so that the electric system can meet a targeted reliability standard, typically limiting loss-of-load events to often one outage every ten years. The capacity expansion modeling phase of an IRP uses the capacity contribution of each resource to ensure that the overall system can meet demand across all hours with a pre-defined level of reliability. The goal of the optimization model is to meet load at the selected level of reliability in a least-cost manner while also achieving any policy requirements within the jurisdiction (including renewable portfolio standards, coal retirement guidelines, energy efficiency requirements, etc.).

Due to the interactions between resources, analyzing the capacity value of future solar on its own will not result in accurate planning of reliability requirements. The contribution of a resource towards system resource adequacy depends on the characteristics of the other resources in the portfolio; resources have interactive effects with one another such that a portfolio of resources may provide a capacity contribution that is greater than (or smaller than) the sum of individual resources on their own. Solar and storage, for example, tend to have a positive interactive effect when added to a portfolio. These positive interactive effects are commonly referred to as "diversity benefits."

The solar generation during the day effectively narrows the duration of the net peak period, and this in turn allows energy storage to more effectively meet the net peak. The solar resources help to satisfy daytime energy demand, while the energy storage resources can help to satisfy evening or morning energy demand. Other resource combinations may produce similar interactive effects; for instance, a portfolio that combines wind and solar typically provides positive interactive effects. These dynamics with respect to solar and storage are shown in Figure 3 below, which is not a Duke-specific figure but illustrates these concepts.

Figure 3: Illustration of the Synergistic Effects of Solar and Storage



There are synergistic interactions between solar and storage. Due to the dynamics above, storage is more effective at satisfying short peaks found in the winter (for example two hours from 7:00 to 9:00am) as opposed to longer-duration peaks that typically occur in the summer. Thus, on a dual-peaking system like Duke's, adding storage can shift the likelihood of loss of load events from winter to summer, when solar is more effective.

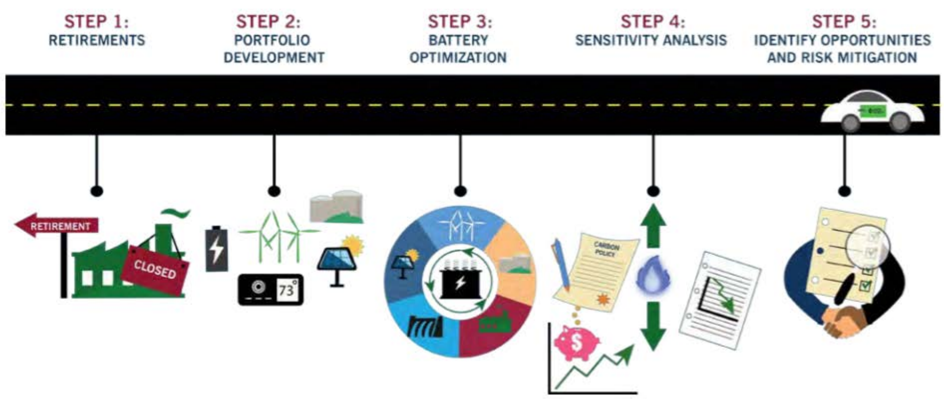
It is critical that any IRP portfolio optimization, including capacity expansion modeling, is done in a single step. Single-step optimization occurs when all components of the capacity expansion are optimized at the same time, as opposed to sequentially. This is crucial due to the interactive effects renewable and storage resources that can only be captured when they are evaluated simultaneously. A capacity expansion model with single step optimization will consider the interactions described in Figure 2 and appropriately measure the combined value of solar and storage resources on the system. By contrast, in a multi-step optimization, one where different resources are evaluated sequentially, solar might not be added as it would not contribute to the evening peak, while storage might not be added because of insufficient duration. Only a single-step optimization, evaluating all generation resources simultaneously, can take into account these synergistic effects.

When considering diversity benefits of renewable resources and energy storage, it is important to note that these resources do not have to be co-located or share an ownership structure. In other words, diversity benefits do not depend on solar being paired directly with storage at the same site – independent solar facilities and storage facilities on a utility's system provide the same benefits. The diversity benefits of both of these resources being installed on a system come from their different operational characteristics as opposed to their geographic location. For example, a battery will be able to charge equally if it is next to a solar plant, or 100 miles away connected by the transmission system. There are times when co-located storage and solar should be modeled as a unique resource due to the operational realities of the facility, however these are unique circumstances, and their modeling would be no different than any other generating asset with unique operations.

3.4 Assessment of Duke Approach

In conducting its 2020 IRP, Duke sequentially analyzed coal retirements, portfolio development, and battery optimization. In other words, Duke used multi-step optimization rather than single step optimization in its IRP. An illustration of this process from Duke's IRP is provided in Figure 4.

Figure 4: Visual Representation of the Duke IRP Process[4]



One of the key attributes of renewable and storage resources is that the economic, reliability, and environmental benefits that these resources provide can only be realized in conjunction with one another. For example, see Section 4.2 for more information on the ELCC diversity benefits that result from adding solar and storage together.

Unfortunately, Duke's sequential approach which analyzes firm retirements, renewable additions, and storage additions in isolation from one another fail to capture key benefits that the model can only recognize when these resources are evaluated jointly. Duke's capacity expansion methodology indicates that energy storage is added *after* the optimization is completed by economically replacing natural gas

[4] Duke Energy Progress and Duke Energy Carolinas, 2020 IRPs, Figure A-3

CT's with energy storage. In other words, Duke's model does not even consider storage until CTs have already been chosen, and then storage is evaluated based on its ability to replace those CTs. This methodology for building energy storage does not account for diversity benefits. For example, renewable energy is less valuable without storage, so evaluating renewables before storage will add fewer renewables than is optimal. Since storage is most valuable at higher penetrations of renewables, if a sub-optimal amount of renewables were added, then a sub-optimal amount of storage will be added. Duke's approach to capacity expansion artificially reduces the amount of solar and storage built on the system as the model is unable to accurately account for the synergistic effects.

3.5 Recommended Approach

An enhanced approach for Duke's IRP requires jointly evaluating all resource additions and retirements in a single-step optimization that fully recognizes the benefits (economic, environmental, reliability) each resource can provide. This approach is markedly different from the sequential approach currently in use. Jointly evaluating resources in a single-step optimization can be computationally complex, so a sophisticated approach must be used to ensure the process can be controlled and efficient. The steps below describe a workable improvement to the Duke IRP process in this proceeding which would capture the joint benefits of solar and storage.

Step 1: Develop an ELCC Surface

The first step in this proposed approach involves developing a set of inputs for the optimization model that quantifies the relationship between the installed capacity of resources and their ELCC. By evaluating portfolios with different penetrations of solar and storage, this approach properly captures both the declining ELCC of incremental solar or storage as well as the synergistic benefits that result from adding both together. The ELCC values in this step can be calculated using a loss-of-load-probability model such as the one Duke already uses to create ELCC curves for individual resources.

The result of this analysis is a 'surface' of ELCC values with the x and y axis representing the penetration of solar and storage and the height of the surface representing the combined ELCC of the resources. An example is illustrated Figure 5.

Figure 5: Depiction of Using a Surface to Model ELCCs for Varying Penetrations of Resources

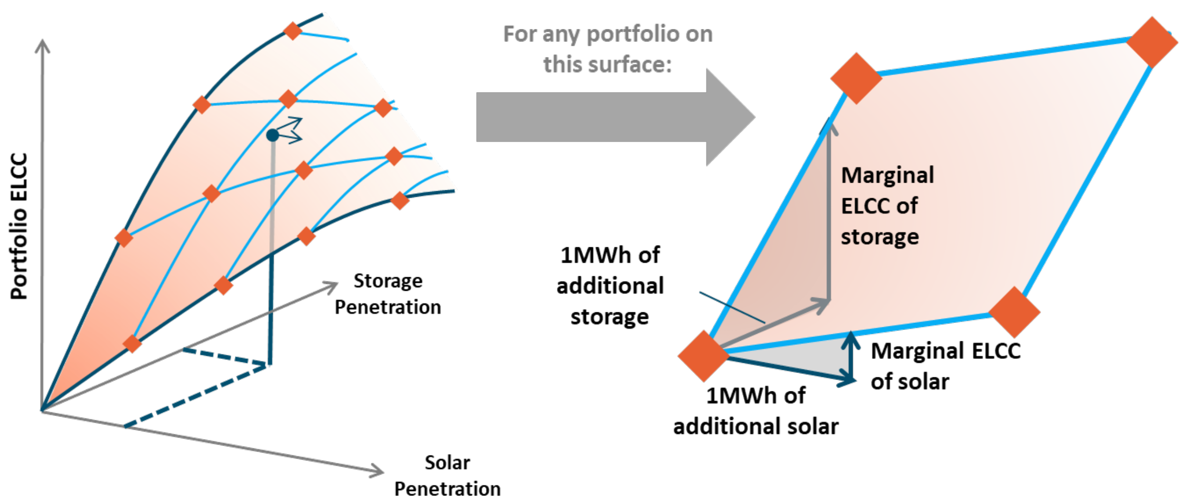


Table 1: Illustrative Values for an ELCC Surface

Combined ELCC Values (MW)		
Installed Solar	Installed Storage	Combined ELCC
0	0	0
100	0	50
100	100	168
200	100	216
200	200	312
300	200	348
300	300	432

ELCC Surface

Stand Alone ELCC Values (MW)			
Installed Solar	Total ELCC	Installed Storage	Total ELCC
0	0	0	0
100	50	100	90
200	90	200	170
300	120	300	240

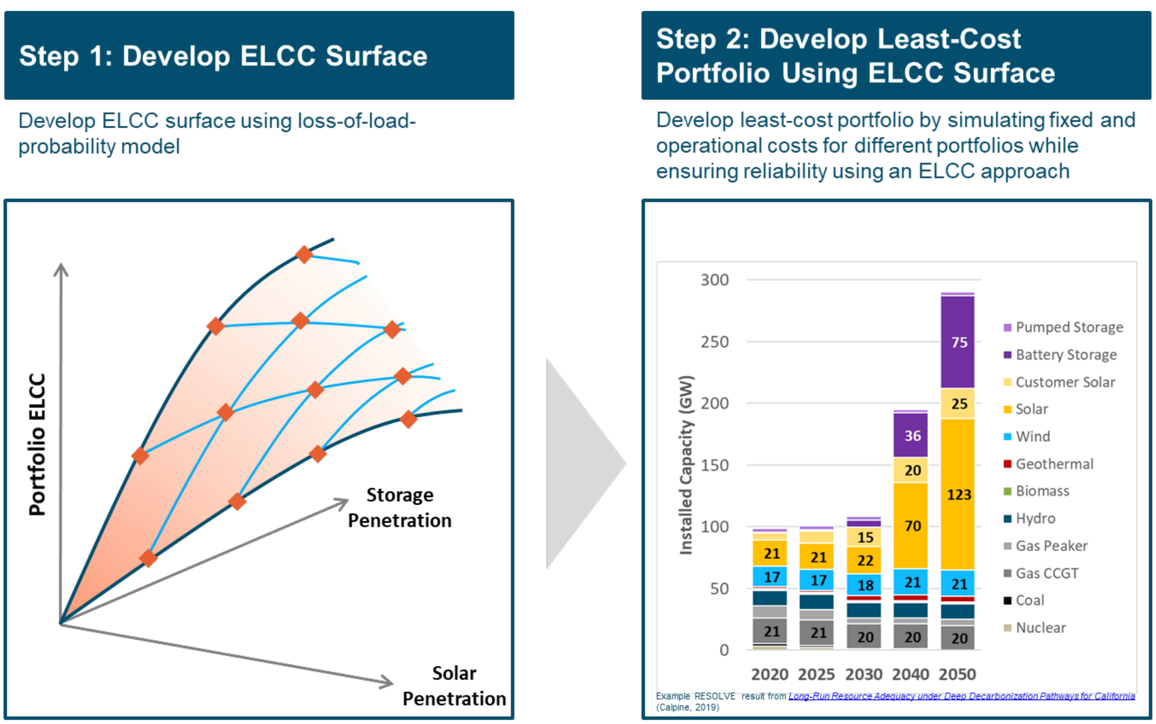
Table 1 shows an illustrative ELCC surface for solar and storage resources on a system. As can be seen, the combined ELCC value of the solar and storage resources is higher than if they are evaluated separately. As an example, 200 MW of both solar and storage on the system has an ELCC of 312 MW while if evaluated separately 200MW of solar and storage would show 260 MW of ELCC (90 MW and 170 MW of ELCC respectively). The use of an ELCC surface allows for the capacity expansion model to incorporate the dynamic synergies of the resources when added to the system.

While this example surface is illustrated for two resources (solar and storage), this framework could be applied to any number of resources to create a multi-dimensional surface that captures the interaction of all various resources. While visualizing a surface with three or more resources is difficult, it is not difficult for an optimization model to incorporate.

Step 2: Develop Least-Cost Portfolio Using ELCC Surface and Single-step Optimization

Portfolio optimization is performed in the electricity industry using a class of 'capacity expansion' models that simultaneously evaluate the capital and operational costs of different portfolios over the long run and select the least-cost portfolio of resources. The capacity expansion model used by Duke should be able to incorporate an ELCC surface in order to evaluate the combined ELCC provided by any combination of solar and storage. This set of values can then be directly compared to the ongoing cost of maintaining or retiring existing coal resources as well as adding new resources such as natural gas. Ultimately, the capacity expansion model should ensure that the system has a sufficient quantity of effective capacity to meet a target level of reliability i.e. peak load plus planning reserve margin.

Figure 6: Illustration of Interaction between the ELCC Surface and Portfolio Results



4 Effective Load Carrying Capability Review

4.1 Astrapé's Solar ELCC Study Critique

Duke recognizes that the capacity contribution of intermittent resources, like solar, decreases with penetration and is aligned with IRP best practices in this regard. While Duke quantifies the capacity value of solar and storage resources using ELCC, many of the assumptions made by both Astrapé and Duke in the preparation of the IRP are not aligned with other aspects of IRP best practices. In this Section, E3 will review the Duke IRP and the 2018 Astrapé Solar Capacity Value Study outlining areas where updates should be made to represent the capacity values of solar and storage accurately and effectively for resource planning.

4.1.1 ERROR IN ACCOUNTING FOR ELCC IN THE PLANNING RESERVE MARGIN

In its IRP, Duke ensures its portfolios meet an "installed capacity PRM", or ICAP PRM to ensure reliability. For firm resources, the seasonal capacity of Duke's firm resources count toward meeting the PRM. For solar and storage, Duke uses the ELCC to determine these resources' contribution to the ICAP PRM. In doing so, Duke's system is under-valuing renewable resources.

By definition, the ICAP approach used by Duke relies on a PRM that is large enough to account for forced outages from existing resources (outages that are unplanned). At the same time, Duke uses ELCC to calculate the equivalent "perfect" capacity contribution of renewable resources to the system – which means that the capacity credit has already been reduced to account for outages. Under this framework, Duke compares apples to oranges by crediting thermal generators with a nameplate capacity credit and renewable and storage resources with reduced capacity credit.

Because of this mismatch, Duke should switch to a UCAP PRM (for planning purposes) that measures all resources on a "perfect" capacity basis.

4.1.2 ELCC SHOULD BE DYNAMIC WITH LOAD LEVELS

The ELCC of a resource is a function of the loads and resources on the system. As more of a resource is added at constant load levels, it effectively provides a larger percentage of total capacity requirements, resulting in a declining ELCC. Conversely, as loads grow, a given resource effectively provides a lower percentage of total capacity requirements, resulting in an increasing ELCC. For example, the ELCC of 100 MW of solar on a system of a 15,000 MW peak load, is going to be approximately 50% greater than 100 MW of solar on a smaller but otherwise equivalent system of 10,000 MW peak load.

Duke calculates solar ELCCs relative to 2020 load levels and storage ELCCs relative to 2024 levels. This approach effectively underestimates the ELCC of solar and storage in years beyond 2020 and 2024 when load levels will be higher.

Duke should use ELCC values which are dynamic to the system including the level of other renewables resources on the system (synergistic effects), as well as future load levels. If this is not possible given the modeling software used, Duke should use ELCC values calculated using load levels consistent to the last year in the planning horizon so that procurement is guided by the long-run capacity value of resources.

4.1.3 DEMAND RESPONSE ASSUMPTIONS ARE OUT-OF-DATE

In its Winter Peak Demand Reduction Potential Assessment report, Duke shared an updated forecast for the potential of demand response programs.[5] This forecast showed a significant increase in demand response potential in the winter relative to the levels assumed in its ELCC studies. More demand response capacity in the winter would move loss-of-load expectation to the summer, increasing the capacity value of solar. Duke's current ELCC values do not reflect this and should be updated to account for the additional 766MW and 507MW of demand potential identified under the Mid Scenario for DEC and DEP respectively.[6]

It should be noted that E3 has not investigated the technical feasibility of the forecasted DR resource amounts and simply is indicating that the IRP should reflect Duke's own most up to date calculations.

4.1.4 STORAGE SHOULD BE DISPATCHED TO PRESERVE RELIABILITY

In the Astrapé ELCC study, three modes of possible storage operation are identified:

+ **Preserve reliability mode:** where the battery is dispatched strictly to maximize system reliability;
+ **Economic arbitrage mode:** where the battery is operated in order to maximize the economic value of the battery; and
+ **Fixed dispatch mode:** where the battery is operated relative to a pre-determined schedule that does not consider real-time system conditions.

E3 recommends the use of "preserve reliability" mode when incorporating the ELCC of storage into portfolio optimization. Using this mode of dispatch to quantify the ELCC value of storage only assumes that storage is operated this way during the very limited days/hours per year when the system is stressed

[5] Duke Energy, Winter Peak Demand Reduction Potential Assessment, December 2020
[6] Duke Energy, Winter Peak Demand Reduction Potential Assessment, December 2020 – Table 14

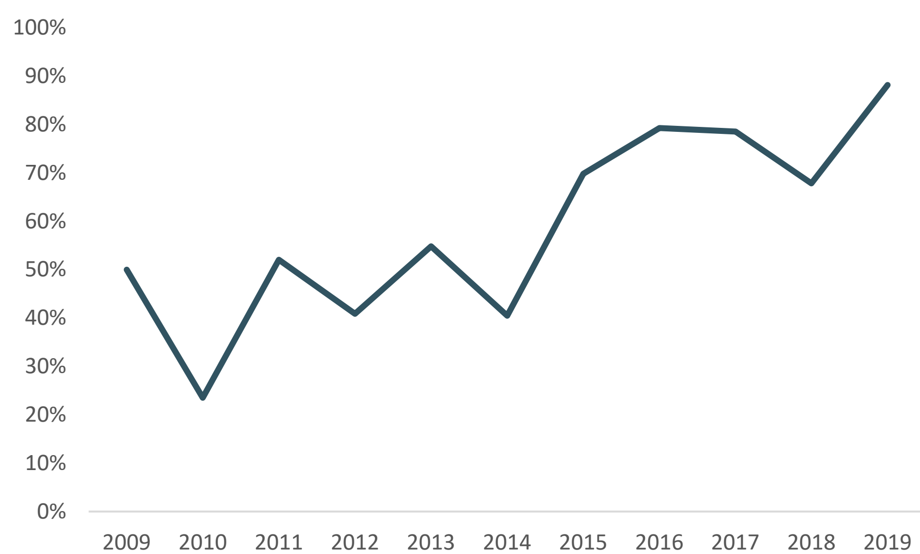
and at risk of loss of load and does not preclude an economic arbitrage mode of operation during all other times. Due to the large economic losses incurred with loss of load, a dispatch approach that maximizes reliability is also one that maximizes system economic value.

In order to effectively use storage to meet system needs during peak events – such as critical winter peaks – Duke's system operators must have enough foresight of these stressed system conditions to charge and hold batteries to serve these periods. Fortunately, given that these stressful system events are driven by highly forecastable weather events, system operators are able to see these events coming with ample time to charge and hold batteries to discharge when they are needed the most. Duke inherently agrees with this assessment since it gives full capacity credit to thermal resources that cannot start instantaneously and must have sufficient foresight to forecast when they will be needed for reliability events. Duke should treat storage resources equivalently and incorporate ELCC values consistent with a preserve reliability mode.

4.1.5 SOLAR TRACKING ASSUMPTIONS ARE LOW

In its Solar Capacity Value Study, Astrapé assumes that 40% of future solar is fixed-tilt and that 60% of future solar is single axis tracking. Technological advancements and cost decreases in tracking systems for solar plants has resulted in near zero future installations of fixed-tilt solar across U.S. jurisdictions.

Figure 7: Utility Scale Tracking Solar Installed as a Percentage of Total[7]



Furthermore, decreasing costs of tracking devices has resulted in the 2018 installed price of solar being roughly equal for fixed-tilt and tracking projects at $1.40/W$_{ac}$ and $1.46/W$_{ac}$ respectively.[8]

Given the near price parity and the clear industry shift to tracking, E3 recommends that the marginal ELCC of solar be based on 100% tracking solar for new installations.

4.2 E3's Effective Load Carrying Capability Modeling

To quantify impact of the combined recommendations identified above in Section 4.1, E3 used its RECAP model, documented in Appendix 1, to calculate both solar and storage ELCCs for the DEC and DEP systems.

[7] Berkeley National Lab and Energy Information Administration. Utility Scale Solar Data Update: 2020 Edition
[8] Id.

Data for this modeling was sourced from Duke's IRP, provided through data requests, and where data was not provided by Duke, E3 used reasonable assumptions.

4.2.1 E3 SOLAR ELCC

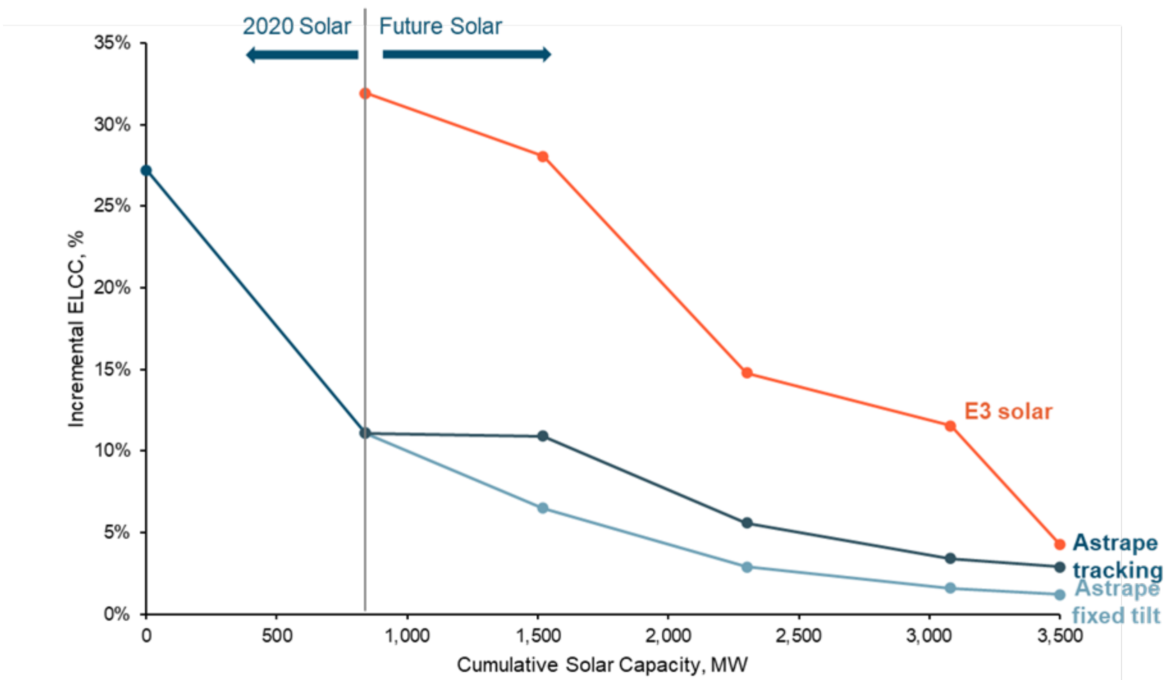
E3 used its RECAP model to calculate the ELCC of solar on the DEC system, incorporating recommended updates outlined in Section 4.1. Specific modeling changes include:

+ The use of 2040 load levels as opposed to 2020 levels;
+ Increased levels of demand response aligning with the Winter Peak Demand Reduction Potential Survey[9] update;
+ Existing pumped hydro resources were modeled in preserve reliability mode; and,
+ All new solar was modeled as tracking.

The resulting increases in solar ELCC for the DEC system are shown in Figure 8 along with Astrapé's 2018 Solar Capacity Value Study results.

[9] Duke Energy, Winter Peak Demand Reduction Potential Assessment, December 2020

Figure 8: E3 Modeling of Solar ELCC on the Duke Energy Carolina's System



As shown, the initial E3 ELCC values of solar are significantly higher than Astrapé's values, with the ultimate results converging at higher penetrations around 3,500 MW. Based on the modeling performed by E3, it is not possible to allocate the differences to each individual recommendation as they are modeled as a package. However, it is accurate to say that all the recommendations made by E3 would have the effect of increasing the solar ELCC values compared to the Astrapé study.

Finally, it should be noted that due to the lack of availability of data, the following assumptions were made in E3's modeling efforts.

+ **Hydro energy budgets** were approximated at the annual level from the Astrapé study and split evenly between months. The data request for actual historical hydro data was denied by Duke.
+ **Imports** were modeled as firm capacity rather than regional production simulation.

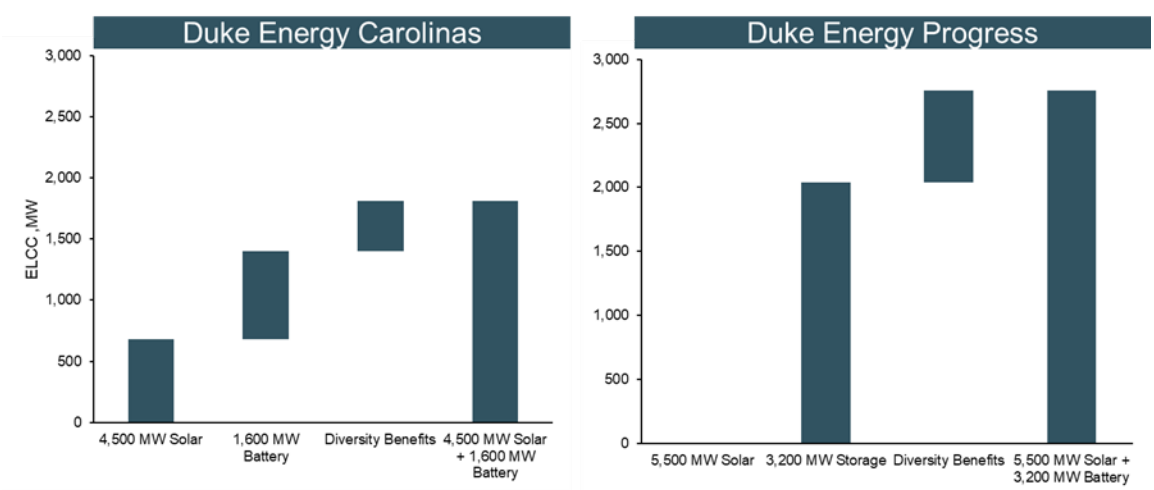
- **Forced outage rates** were modeled as an average rate by unit received for data request response. Astrapé aggregates historical outages from the NERC Generating Availability Data System.
- **Demand Response** was modeled based on average duration from historical calls. Astrapé models demand response with hourly flexibility.

4.2.2 DIVERSITY BENEFITS BETWEEN SOLAR AND STORAGE

As discussed in Section 3.4, Duke's IRP does not accurately account for the diversity benefits between solar and storage additions to the system. The Astrapé 2018 Solar Capacity study presents ELCC values for solar and storage independently, assuming no new installation of either resource. Under this framework the synergistic value of installing both new solar and storage assets is lost.

Using the RECAP model, E3 quantified the relative amounts of diversity benefits under a specific scenario for each of the DEP and DEC systems, the results are shown in Figure 9.

Figure 9: Quantification of ELCC and Diversity Benefits from Solar and a 4-hour Storage Device



In the Duke Energy Carolina system, 4,500 MW of solar and 1,600 MW of batteries have an ELCC of 1,800 MW. Yet, 400 MW, or 20% of that value comes from the synergistic interactions of solar and storage.

Likewise, for Duke Energy Progress, 5,500 MW of solar and 3,200 MW of batteries have a combined ELCC of 2,800 MW, with 670 MW, or 25%, due to diversity benefits.

Figure 9 clearly shows that under a multi-step optimization, where solar and storage would be considered independently, 20-25% of the capacity value would be un-accounted for. The ultimate consequence of this is that both solar and storage are under optimized.

5 Recommendations

5.1 IRP Modeling Recommendations

Section 3 outlines a best-in-class approach to IRP, areas where Duke Energy falls below that standard, and recommendations for improvement. The recommendations are summarized here.

5.1.1 USE OF A SINGLE STEP OPTIMIZATION WITH DYNAMIC ELCCS

Duke's use of a multi-step portfolio development process does not adequately capture the diversity benefits associated with renewables and storage. By evaluating the benefits of solar and storage at separate points in the capacity expansion process, diversity benefits are ignored, leading to other technologies being chosen at a higher cost.

E3 recommends that Duke re-run the capacity expansion component of their IRP using a single-step optimization methodology that allows for the diversity benefits of solar and storage to be captured. This will likely lead to more solar and storage being selected by the model and is the most significant improvement that can be made within the scope of this report.

5.1.2 USE OF UCAP PRM

Duke's current use of an ICAP PRM, paired with ELCC values for solar and storage compares apples with oranges and disadvantages renewables and storage assets. Currently, thermal firm resources are credited their full nameplate capacity while renewable and storage assets are credited with an ELCC value that is by definition equivalent to perfect capacity.

To allow for an accurate accounting, Duke should move to the use of a UCAP PRM under which thermal resources, renewable resources, and storage resources would be de-rated based on both their forecasted outage rates and variability. E3 also understands that this would require a significant re-design of the current PRM process and thus as a potential work around, the ELCC values for solar and storage could be grossed up by the outage rates of a standard thermal unit in order to create a level playing field.

5.2 Effective Load Carrying Capability Recommendations

In Section 4, E3 reviewed Astrapé 2018 Solar ELCC Study, provided recommendations for improvements, and provided modeling results indicating the impact of those recommendations. Those recommendations are summarized here:

5.2.1 GENERATE AN ELCC SURFACE FOR SOLAR AND STORAGE

The interactive effects of solar and storage on the DEC system can only be fully understood by developing an ELCC surface that determines the combined capacity value of different portfolios of solar and storage (see Figure 5).

Duke should update the 2018 Solar ELCC Study to include an ELCC surface analysis that demonstrates the increasing diversity benefit associated with solar and storage installations. This recommendation is also critical in developing an optimized capacity expansion.

5.2.2 UPDATE 2018 SOLAR CAPACITY VALUE STUDY

As described in Section 4.1, E3 has a number of recommendations to increase the accuracy of ELCC calculations for solar on the DEC system. These recommendations are also applicable to the calculation of an ELCC surface. Specifically, Duke should:

- Vary ELCC as a function of load level. By limiting the ELCC calculation to the 2020/2024 load levels, ELCC are being artificially depressed in future years by not taking into account load growth. If Duke or Astrapé is unable to vary ELCC levels with load, then Duke should base ELCC values on 2040 load levels to reflect the long-lived nature of the assets.
- Update DR values to include those identified in the Winter Peak Demand Reduction Potential Assessment.
- Model energy storage resources on a preserve reliability basis as opposed to an economic arbitrage basis.
- Change future solar technology assumption from 60% tracking to 100% tracking.

6 Conclusion

As technologies and policies have evolved in the electricity industry, the long-term planning of electric systems has become increasingly complex. The increasing installation of renewables and energy storage necessitates an evolution of IRP to accurately account for the potential benefits brought to the system and achieve a least-cost solution.

E3's four recommendations, moving to a single-step optimization, moving to a UCAP PRM, using an ELCC surface to account for diversity benefits, and aligning the demand response benefits to the most recent Duke study, are instrumental in achieving an IRP outcome that is least-cost. Without taking these steps, Duke's generation resource options will not have been compared on an apples-to-apples basis and as such will have resulted in a higher cost solution.

E3 recommends that Duke be required to re-file its IRP updating the assumptions and methodologies to align with the findings of this report.

7 Appendix 1 – E3 RECAP Model

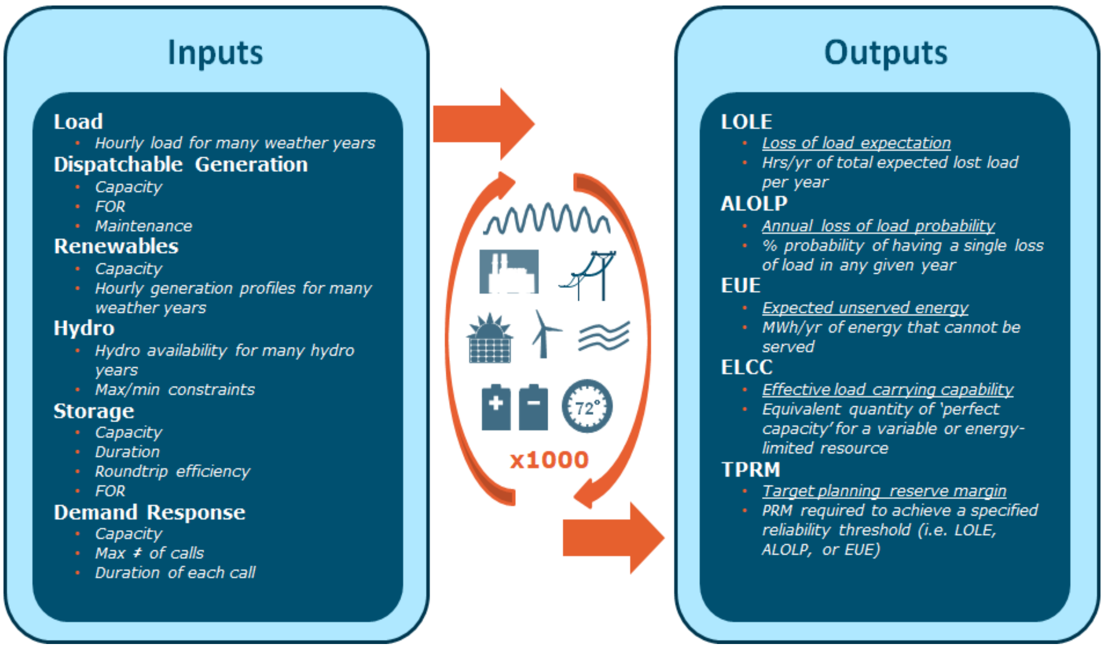
7.1.1 E3'S RENEWABLE ENERGY CAPACITY PLANNING MODEL (RECAP)

RECAP is a loss-of-load-probability model designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response. RECAP was initially developed for the California Independent System Operator (CAISO) in 2011 to facilitate studies of renewable integration and has since been adapted for use in many jurisdictions across North America.

RECAP evaluates resource adequacy through time-sequential simulations of thousands of years of plausible system conditions to calculate a statistically significant measure of system reliability metrics as well as individual resource contributions to system reliability. The modeling framework is built around capturing correlations among weather, load, and renewable generation. RECAP also introduces stochastic forced outages of thermal plants and transmission assets and time-sequentially tracks hydro, demand response, and storage state of charge. Through modeling the electric system under different combinations of these characteristics, loss-of-load expectation (LOLE) for the electric system is calculated.

Figure 10 provides a high-level overview of RECAP including key inputs, Monte Carlo simulation process, and key outputs.

Figure 10: RECAP Model Overview



Effective Load Carrying Capability Calculation

RECAP's simulation of LOLE for a given electric system enables the calculation of ELCC for individual resources. These ELCCs for individual resources (or combinations of resources) are calculated through iterative simulations of an electric system:

1. The LOLE for the electric system without the specified resource is simulated. If the resulting LOLE does not match the specified reliability target, the system "adjusted" to meet a target reliability standard (most commonly, one day in ten years). This adjustment occurs through the addition (or removal) of perfect capacity resources to achieve the desired reliability standard.
2. The specified resource is added to the system and LOLE is recalculated. This will result in a reduction in the system's LOLE, as the amount of available generation has increased.

3. Perfect capacity resources are removed from the system until the LOLE returns to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of the specified resource (measured in MW); this metric can also be translated to percentage terms by dividing by the installed capacity of the specified resource.

Figure 11: Iterative Approach to Determining Effective Load Carrying Capability

This approach can be used to determine the ELCC of any specific resource type evaluated within the model. In general, ELCC is not widely used to measure capacity value for firm resources (which are generally rated either at their full or unforced capacity) but provides a useful metric for characterizing the capacity value of renewable resources and storage.

DIRECT TESTIMONY OF ARNE OLSON
ON BEHALF OF
THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

EXHIBIT AO-3

DUKE ENERGY

Winter Peak Demand Reduction Potential Assessment

December 2020

PREPARED FOR:

Duke Energy Corporation
550 S. Tryon Street
Charlotte, NC 28202
US

www.duke-energy.com | +1 980.373.2780

PREPARED BY:

Dunsky Energy Consulting
50 Ste-Catherine W., suite 420
Montreal, QC, H2X 3V4
Canada

www.dunsky.com | info@dunsky.com
+ 1 514 504 9030

IN PARTNERSHIP WITH:

Tierra Resource Consultants
1501 North Broadway, suite 300
Walnut Creek, CA 94596
US

www.tierrarc.com | floyd.keneipp@tierrarc.com
+ 1 925-954-7363

TABLE OF CONTENTS

1 WINTER PEAK DSM POTENTIAL MODELING OVERVIEW

Duke Energy North Carolina and South Carolina engaged Dunsky Energy Consulting, as part of the Tierra Inc team to model the winter peak demand reduction potential in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems.

The objectives of this modelling exercise were to

1) Capture the potential for new programs and measures to reduce the winter peak demand in each of DEP and DEC, via Demand Side Management (DSM) programs target to residential and commercial customers
2) Quantify the degree to which this potential is incremental to the current Duke DSM program impacts, and compare the findings to the Market Potential Study, recently conducted by Nexant[1].
3) Provide insights that can help Duke prioritize winter peak DSM approaches in the short term, as well as identify the potential for longer term strategies.

Following on Tierra's work to identify and characterize new rate structures and mechanical solutions, the winter peak DSM potential assessed the ability of behavioral measures, equipment controls and industrial and commercial curtailment to reduce Duke's overall system peak in each system.

The report includes an introduction to the modelling methodology, followed by a step-by step description of the model findings. The overall potential assessment is then provided in section 3 of this report, followed by a concluding section containing key take-aways. Finally, a set of detailed results and input assumptions is appended.

1.1 DSM POTENTIAL ASSESSMENT APPROACH

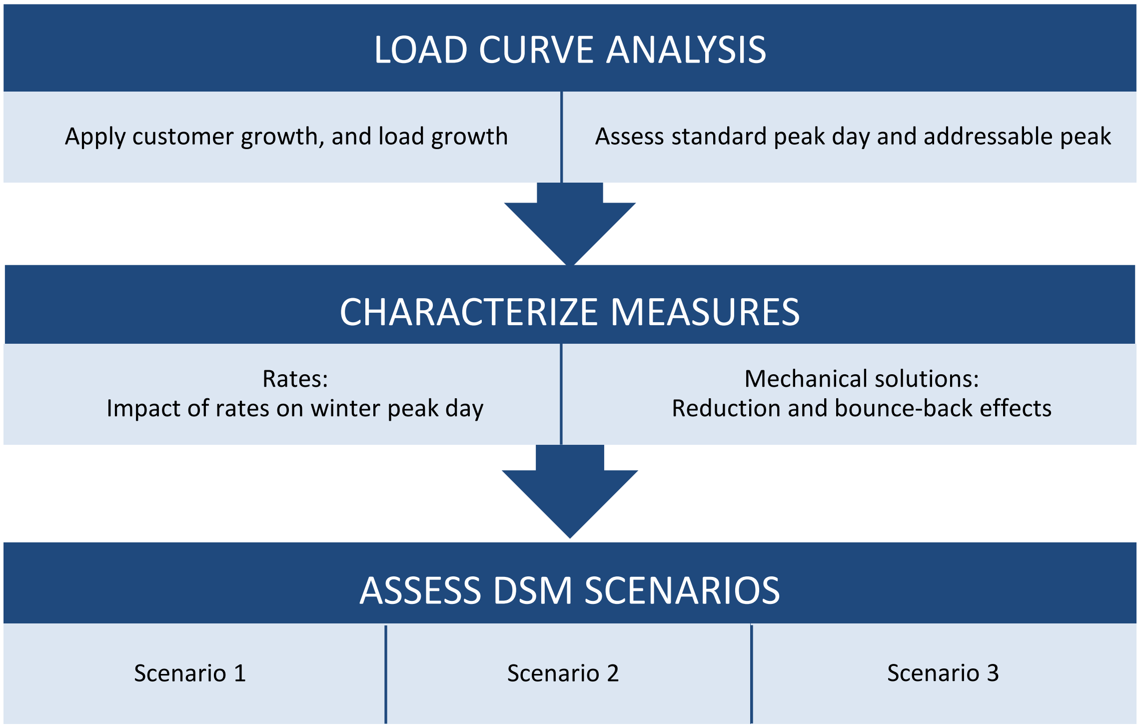
The DSM potential is assessed against Duke's hourly system load curves and winter peak demands. Figure 1 below presents an overview of the steps applied to assess the DSM potential in this study.

Key to this assessment is the treatment and consideration Duke's DEC and DEP winter system peak-day hourly load curve. As part of this process, standard peak day 24-hour load curves are identified and adjusted to account for projected load growth over the study period. This allows the model to assess each measure's net reduction in the annual peak, considering possible shifts in the timing and duration of the annual winter peak in each system.

In some cases, this may lead to results that are contrary to initial expectations, especially when DSM programs such as dynamic rates or equipment direct load control (DLC) measures are looked at only from the perspective of how they may impact individual customer peak loads at the originally identified peak hour.

[1] Nexant, *Duke Energy North Carolina EE and DSM Market Potential Study,* and *Duke Energy South Carolina EE and DSM Market Potential Study*, May 2020

Figure 1 - DSM Potential Assessment Approach



The achievable potential is assessed under three scenarios corresponding to varied DSM approaches or strategies (Figure 2). These scenarios were developed with the goal of assessing the impacts of different rate structures and a selected set of mechanical solutions on the load curve of both DEC and DEP. More details on the scenarios can found in the section 3.3 of this report.

Figure 2. Demand Response Program Scenario Descriptions

LOW	Applies a limited number of rate structures with conservative adoption or incentive levels in conjunction with a defined set of mechanical solutions.
MID	Introduces an additional rate structure into the residential market and increases C&I adoption or incentive levels. Mechanical solutions are adapted to the new rate structures.
MAX	Applies a variety of residential rate structures and more aggressive C&I adoption and incentive levels to estimate maximum achievable potential. Mechanical solutions are adapted to the new rate structures.

1.2 SEGMENTATION

Market segmentation is essential to accurately estimate the DSM potential and is one of the first step of the modelling. Customer information provided was broken down by rate class for both DEC and DEP. As rates patterns and DSM savings vary by customer characteristics, DEC and DEP customers were segmented in three ways:

- **By market sector**: Residential, Commercial and Industrial

- **By rate class**: Within each sector, customers can choose a variety of rate classes, depending on their overall size (assessed by annual peak kW power draw) and rate structure preference. By segmenting customers according to their applicable rate classes, the model can assess the impact of customers moving to new or adjusted rate structures. The key rates classes in both DEP and DEC and presented in Table 1. Both "other" rates encompass all the other rates not specifically mentioned that are available in each system.

Table 1 – Rate Class Segmentation

DEC - Rates	DEP - Rates
SGS	SGS
LGS	MGS
OPTC	LGS
OPTI	RTP
RS	Res
RE	Other
Other	

- **By customer segment:** Within each market sector/rate class segment, Duke's commercial and industrial customers were further segmented by business type (i.e., offices, schools, retail etc.) using U.S. Energy Information Agency's (EIA) Commercial Buildings Energy Consumption Survey (CBECS - 2012) and Residential Energy Consumption Survey (RECS - 2015).

2 DSM POTENTIAL ASSESSMENT

2.1 STEP 1 - LOAD CURVE ANALYSIS

The peak load analysis is the first step in the DSM potential analysis, through which key constraints are defined to identify the solutions that will be deployed, and the scenarios modelled to reduce winter peak demands.

First, the winter season standard peak day load curve is defined, and the impacts of load growth projections are applied. The standard peak day load curve for the electric system is defined by taking an average of the load shape from each of the top ten winter peak days in the forecasted hourly load data provided[2] (Figure 3 for DEC and Figure 4 for DEP).

Figure 3 - DEC Standard Peak Day (incl. wholesale) Based on Historical Data – 2020

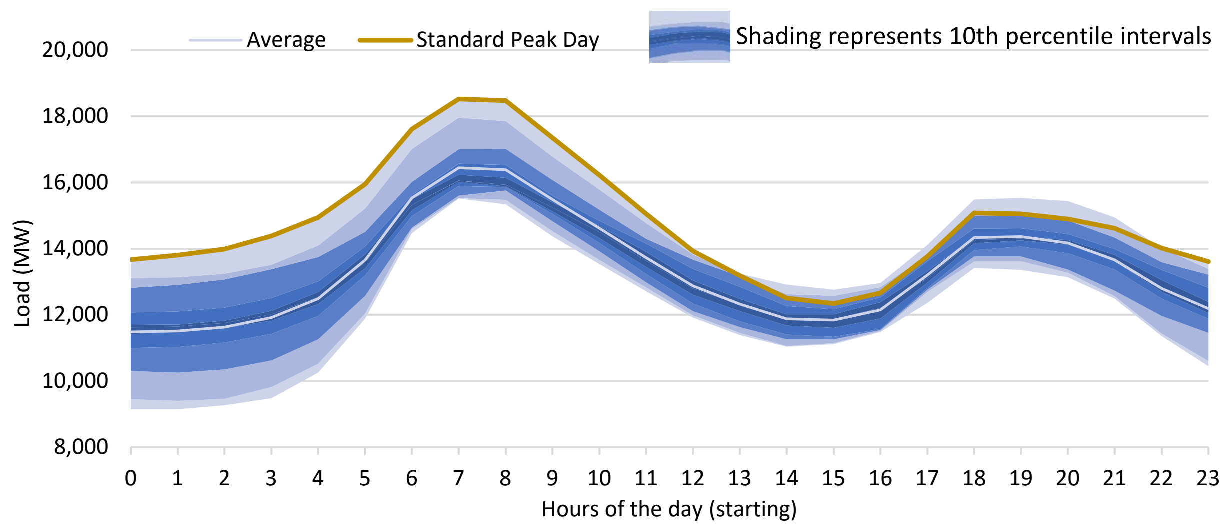
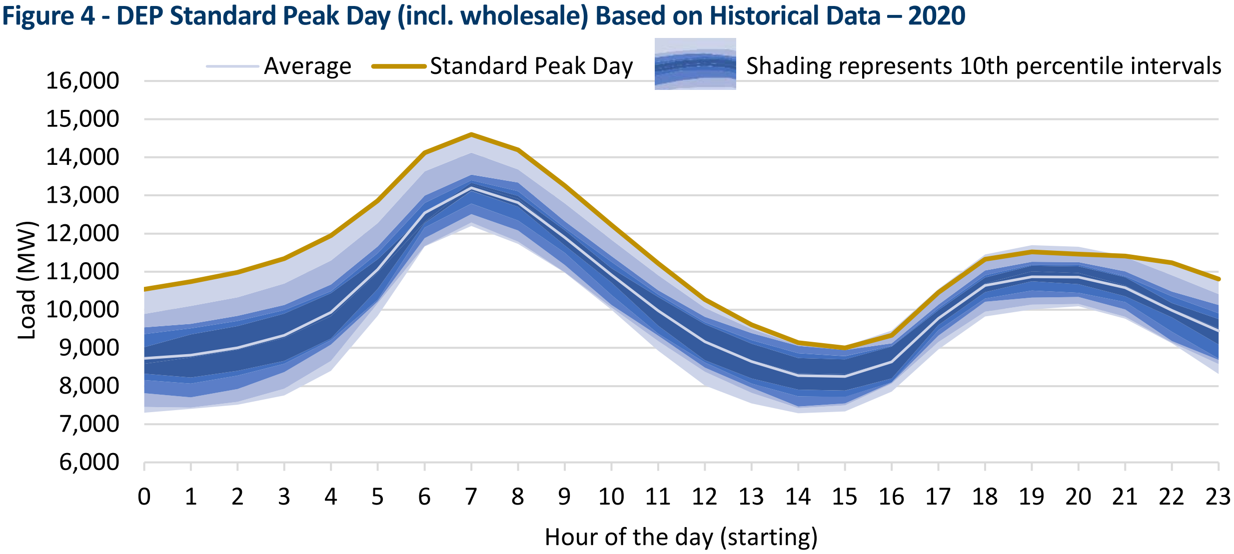


Figure 4 - DEP Standard Peak Day (incl. wholesale) Based on Historical Data – 2020



[2] Provided forecast included years between 2020 and 2045.

This analysis shows that Duke's systems, in winter, have a steep morning peak, which is driven predominantly by residential and commercial space heating. The duration and steepness of the peak curve indicate that measures with bounce-back or pre-charge effects are not likely to pose a real problem in winter by creating new peaks when shifting load from one hour to another.

An hourly load forecast was provided, for each year from 2021 to 2041, thus the winter peak load curve assessment was repeated for each year to determine the annual winter peak in each of the year of the study period (2021-2041), resulting in the peak day characteristics listed in Table 2 below.

Table 2 – Standard Peak Day Key Metrics

Year	Peak Demand (MW) excl. wholesale	
	DEC	DEP
2021	16,533	10,551
2026	16,611	10,661
2031	17,242	11,020
2036	18,191	11,593
2041	19,315	12,332

Once defined, the standard peak day utility load curve is then used to characterize the DSM solution set measures, by defining the peak load reduction possible at each hour of the day. These are then used to assess the measure-specific peak demand reduction potentials at the technical and economic potential levels.

2.2 STEP 2 - SOLUTION SET CHARACTERIZATION

Based on the load analysis and detailed review of Duke's current program and rates[3], a solution set was developed to reduce the winter peak demand in both DEP and DEC. The mechanical solutions and rate structures considered are described below.

2.2.1 MECHANICAL SOLUTIONS

As outlined in Tierra's Winter Peak Analysis and Solution Set report, a solution set was identified to specifically address the DEC and DEP winter peak. Once selected, measures were characterized individually. Measure characterization is the process of determining the hourly load curve impacts (kW reductions in each hour), as well as the measure costs, applicable markets and EULs. The measure characterizations leverage a range of secondary sources, including energy modelling profiles and empirical data from relevant jurisdictions to determine the resulting load curve impacts.

Based on the Winter Peak Analysis and Solution Set report analysis, a total of eight technologies/programs were chosen to be integrated into the modelling.

[3] More details are provided in Tierra's Winter Peak Analysis and Solution Set report.

- **Residential**
    - Bring Your Own Thermostat (BYOT)
    - Rate Enabled Thermostats (RET)
    - Rate Enabled Residential Hot Water Heating Controls (RE-HWH)
    - Winter Heat Pump Tune-up
    - Battery Energy Storage[4]
- **Small and Medium C&I**
    - Bring Your Own Thermostat (BYOT)
    - Rate Enabled Thermostats (RET)
    - Winter Heat Pump Tune-up
- **Large C&I**
    - Automated Demand Response (ADR) for larger C&I flat rate customers selecting advanced rates

More details on the key measure inputs are provided in the Winter Peak Analysis and Solution Set report.

2.2.2 RESIDENTIAL RATES

Close attention was paid to the rates structure as they not within the scope covered by Nexant's 2020 MPS study, and thus they provided an opportunity to determine if and where further potential for winter peak reductions may lie. Rates are used to encourage customers to modify their behavior and change consumption patterns. Four specific rates structures were designed for the study, applying the three common residential dynamic rate structures: Time-Of-Use Rate (TOU), Critical Peak Pricing (CPP) and Peak Time Rebate (PTR). Based on the load curve analysis, the peak hour charges were applied from 5:00 am to 9:59 am on weekdays only.

- **TOU Rate**
- **TOU Rate with CPP**
- **Bill Certainty with PTR**
- **Flat Volumetric with CPP**

Further details on the Residential DSM rates are provided in the appendix.

[5]

2.2.3 COMMERCIAL & INDUSTRIAL RATES

Commercial rates were derived for customer segments small, medium, and large annual consumption profiles. Both CN&I rates apply PTR rates to attract customers by providing a benefit for demonstrated

---

[4] The forecast of residential Battery Energy Storage represents a conservative view based on uncertainties about market adoption for this technology and is discussed in more detail in the Winter Peak Plan report completed as part of this same research effort.

[5] The reports produced by the Winter Peak Study, including the Winter Peak Demand Reduction Potential Assessment report, use the term Commercial and Industrial to discuss rates used by the non-residential market sectors and is intended to help define the significant difference in load shapes between commercial and industrial customers and also define DSM opportunities targeting each market segment, Commercial and Industrial rates and customers may be referred to as "Non-residential" or "General Service" rates in other Duke publication and communications.

peak event demand reductions. By using a rebate approach, PTR rates is particularly attractive to large customers who see in it as a win-win situation. Considering the variety of C&I rates as well as the option for large customers to opt-out from DSM programs, this rate is potentially an opportunity to attract more customers than current DSM programs. The rate consists of offering a rebate for reducing their load below a customer-specific baseline during peak times

- **Small C&I Customers – Bill Certainty with PTR**
- **Medium and Large - C&I Customers - PTR**

For modelling assumptions, to avoid any double-counting, participants already enrolled under current DSM programs (DRA or PowerShare) are excluded from the customers count. Further details on the C&I DSM rates are provided in the appendix.

2.3 STEP 3 - SCENARIOS

As a final analysis step, three defined adoption scenarios are applied, and the winter peak impacts are assessed. Three scenarios were developed to be viable in both DEC and DEP systems, with key program inputs defined for each. This section summarizes the selected scenarios and main program inputs.

2.3.1 LOW SCENARIO

The low scenario includes a solution set that includes the most straight-forward combination of rate options. A new residential TOU rate structure would be offered along with a TOU+CPP option. On the C&I side, a PTR rate would be deployed with a conservative adoption rate for SGS customers and a low PTR incentive for medium and large C&I.

Table 3 – Overview of the Low Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates	• Small C&I - Bill Certainty + PTR Low adoption (10%) • Medium and Large C&I - PTR Low incentive (30$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I- BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.2 MID SCENARIO

The Mid scenario aims to expand on the Low scenario by including a new residential Bill Certainty rate option and increase adoption and PTR incentives in the C&I sector.

Table 4 – Overview of the Mid Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates	• Small C&I - Bill Certainty + PTR Mid adoption (15%)

	• Bill Certainty + PTR Rates	• Medium and Large C&I - PTR Mid incentive (60$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I - BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.3 MAX SCENARIO

The Max scenario aims to maximize demand response potential by adding a new CPP option, maximizing adoption in small C&I, and increasing medium and large C&I PTR incentives to approach the limits that still render the programs cost effective (i.e., the incentive levels that yield UCT results of 1.2 or higher).

Table 5 – Overview of the Max Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates • Bill Certainty + PTR Rates • Flat Volumetric + CPP Rates	• Small C&I - Bill Certainty + PTR High adoption (20%) • Medium and Large C&I - PTR High incentive (90$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I - BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.4 KEY VARIABLES FOR DSM POTENTIAL ASSESMENT

The variables below are key to the DSM assessment as they feed the achievable potential and costs calculation. These assumptions were developed based on Duke's inputs, jurisdictional scans and professional judgment.

RESIDENTIAL PARTICIPATION RATES

Table 6 below summarizes adoption levels for each DSM rate per under each scenario treatment.

Table 6 – Adoption for Residential Rates*

	Low Scenario			Mid Scenario			Max Scenario		
Target Rate	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**
TOU	2%	10%	5%	2%	10%	5%	4%	20%	11%
TOU + CPP	10%	15%	12%	10%	15%	12%	6%	9%	7%
Bill Certainty + PTR	-	-	-	8%	20%	13%	10%	25%	16%
Flat Volumetric + CPP	-	-	-	-	-	-	4%	11%	7%
Total residential Market	***12%***	***25%***	***18%***	***21%***	***45%***	***31%***	***25%***	***65%***	***42%***

*Due to rounding, numbers may not add up

Adoption levels were first determined for the DEC all-electric residential rate class (RE). It is expected that this rate class would benefit the most from the selected rates structures (higher electric bills and peak demand) and therefore, the rate with the highest adoption levels. Adoption levels for all-electric residential rate are derived from Brattle's Time-Varying Price Enrollment Rates Study[6], a study that bundles results from six market research studies and fourteen full-scale deployments. Based on this study findings, for an opt-in residential dynamic rate, TOU rates can reach on average 28% of the customers, CPP rates can achieve an average of 17% and PTR rates average 21%.

For the Low scenario, it is therefore assumed that a total of 25% of RE customers would enroll in a TOU rate structure after full deployment of the rates. Of those customers willing to join a TOU rate, it is estimated that 15% would prefer a TOU+CPP version of the rate. For the Mid scenario, the adoption for PTR was assumed to be 20% of RE customers. It is important to note that to keep conservative estimates, the averages for all residential customers from the Brattle study were applied as our highest adoption estimates for the RE rate class only.

Finally, for the Max scenario, the objective was to reach a maximum of customers through large-scale deployment and intensive marketing. It is estimated that a total of 28.5% of customers will be interested in a TOU rates structure, corresponding to the average from the Brattle's Time-Varying Price Enrollment Rates Study. Based on findings from Sacramento Municipal Utility District's Consumer Behavior Study[7], it is assumed that the participation rates between TOU+CPP and a CPP rate would be similar with a slightly preference for a CPP rate structure[8]. This was further corroborated through the preliminary survey results from Duke's Flex Savings Options Pilot. As for PTR, adoption levels as high as 56% were achieved in other jurisdictions. Taking into consideration the multiple rates offered conjointly in this scenario, a maximum adoption of 25% has been selected.

Once RE rate class adoption levels were established, those levels were used to determine the potential adoption for DEC standard residential rate (RS) which mainly includes non-electric heated customers. The adoption levels were assumed to be proportional to the average bill savings. The lower the bill savings, the lower the adoption. Load impact results from the Flex Savings Options Pilot were used to assess the level of achievable savings.

Finally, adoption rates for customers under the DEP residential rates were prorated based on the number of customers all electric versus non-electric heated.

C&I PARTICIPATION RATES

Table 7 below present the incentives and adoption level used for the C&I DSM rate scenarios.

Table 7 – Adoption for C&I Rates

C&I	Low Scenario	Mid Scenario	Max Scenario

[6]Adoption for opt-in dynamic rates from R. Hledik, A. Faruqui and L. Bressan, *Demand Response Market Research: Portland General Electric, 2016 to 2035 – Appendix A: Participation Assumptions*, 2016.

[7] SMUD, *SmartPricing Options Final Evaluation*, 2014. Retrieved at: https://www.smud.org/-/media/Documents/Corporate/About-Us/Energy-Research-and-Development/research-SmartPricing-options-final-evaluation.ashx

[8] The TOU+CPP rate structure had a higher percentage of drop-out customers than the CPP rate structure (7.7% vs 5.7% - Figure 1.2). Our estimates use drop-out percentages rather than acceptance rates because acceptance rates reflect decisions made at the beginning of the pilot, before experiencing the rate.

Bill Certainty + PTR (Small C&I) Adoption	10%	15%	20%
PTR (Medium & Large C&I) Incentives	30$/kW/yr	60$/kW/yr	90$/kW/yr

Small C&I Customers
Adoption levels were also based on Brattle's Time-Varying Price Enrollment Rates, with again a reduction factor to account for the low elasticity of the small C&I sector. Since there is uncertainty in this approach, three scenarios, with various adoption levels were modelled to see the impact of adoption on demand response potential.

Medium & Large C&I Customers
For the medium and large C&I rates, the model determines the expected maximum program participation based on the incentive offered, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves developed by the Lawrence Berkeley National Laboratory[9]. The propensity curve was calibrated to the existing participation level from DRA and PowerShare.

OTHER PROGRAM OUTPUTS

The modelling includes several program inputs. Below are presented a few of these key variables. More detailed are included in Appendix A.2.

Participation and Enrollment Ramp up: Participation and enrollment ramp ups are applied to every modelled solution. The BYOT program is assumed to be deployed in 2021 while all other programs are not assumed to start before 2022 at least. The low scenario assumed a 5-year ramp up for each rate solution while the Mid and Max scenarios assume an 8-year ramp up.

Program Costs: For every DSM program, a one-time fixed cost is applied for program development. For recurring costs, an annual fixed cost is assumed along with a variable cost per customers. Program costs also include sign-up and/or annual incentives.

Program Lifetime: For mechanical solutions, programs are assumed to last for the whole measure life.

[9] Lawrence Berkeley National Laboratory, *2025 California Demand Study Potential Study: Phase 2 - Appendix F*, March 2017. Retrieved at: http://www.cpuc.ca.gov/General.aspx?id=10622

3 DSM ACHIEVABLE POTENTIAL RESULTS

The overall achievable winter DSM potential in each year for each scenario is presented below, and in all cases the values are presented are incremental to current DSM program winter peak impacts. These results represent the overall winter peak load reduction potential when all constituent programs are assessed together against the DEP and DEC load curves, accounting for combined interactions among programs and reasonable roll-out schedules.

Measures that cost-effectively deliver sufficient peak load reductions individually are retained and applied in the achievable potential scenario analysis. Consistent with the other savings modules in this study, only cases where the measure yields a Utility Cost Test (UCT) value greater than 1.1 are retained in the economic and achievable potential.

Under the Low scenario, which represents the most conservative scenario, the winter potential is estimated to reach **1,079 MW in 2041** (651 MW in DEC and 428 MW in DEP), which represents 3.4% and 3.5% of DEC and DEP peak, respectively. Under the Mid and Max scenarios, the achievable potential estimates respectively achieve **1,273 MW** (766 MW in DEC and 507 MW in DEP) and **1,378 MW** (834 MW in DEC and 544 MW in DEP) **in 2041**, translating into 4.0% (DEC) and 4.1% (DEP) for the Mid scenario and 4.3% (DEC) and 4.4% (DEP) for the Max scenario of the systems peaks. Based on these results, the scenario analysis indicates that DSM rate structures that have been piloted by Duke (TOU and TOU+CPP) can capture a little over 45% of the expected potential from DSM rates, while the rest of the potential lies in new rates offers (PTR and CPP).

Figure 5 – DEC potential, by scenario

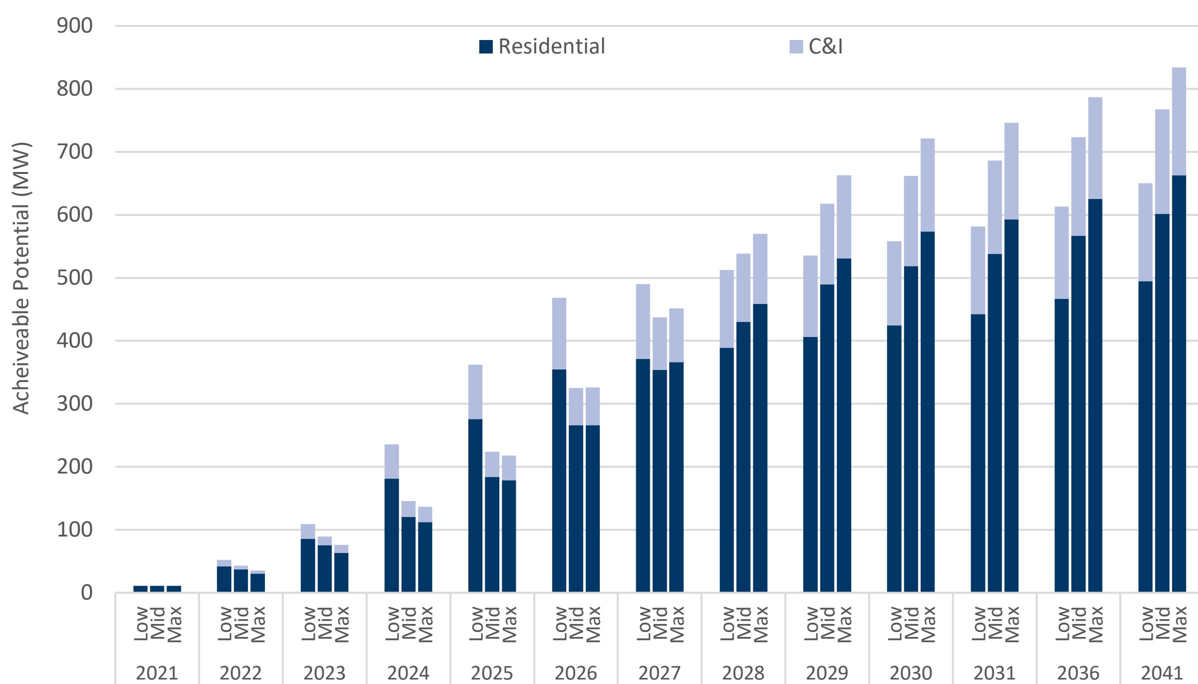


Figure 6 – DEP potential in each study year by scenario

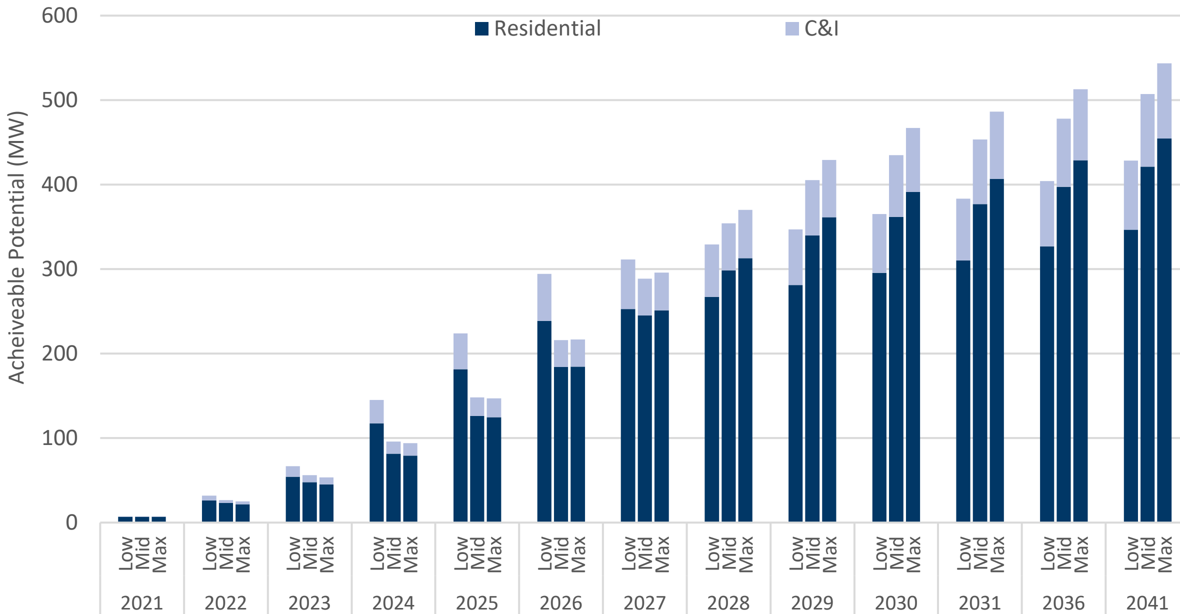
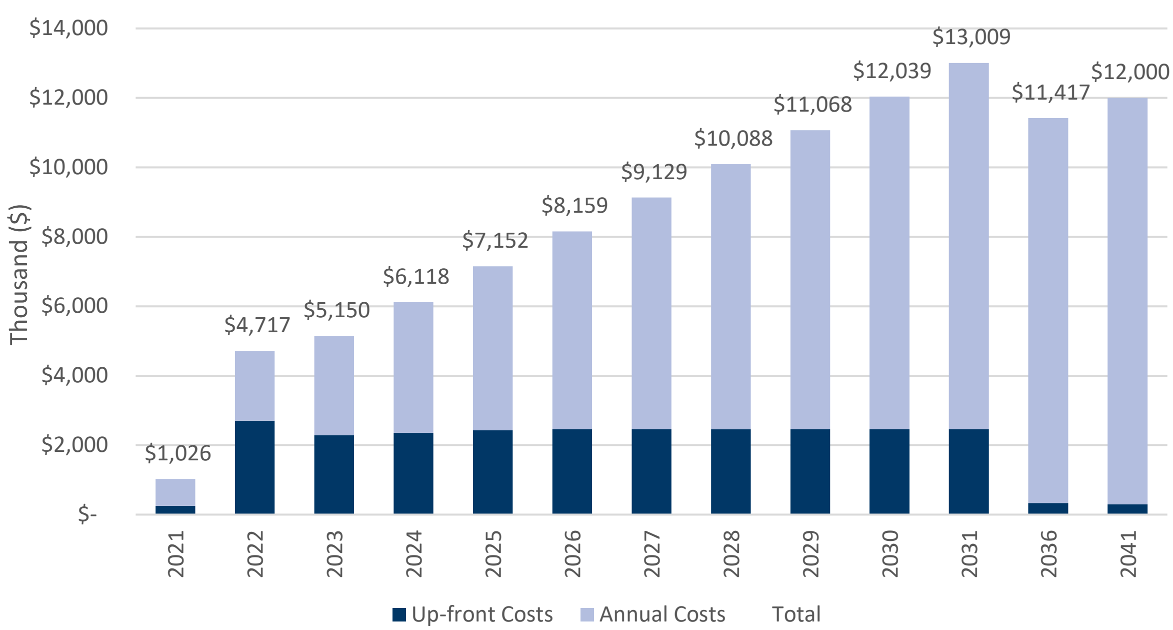


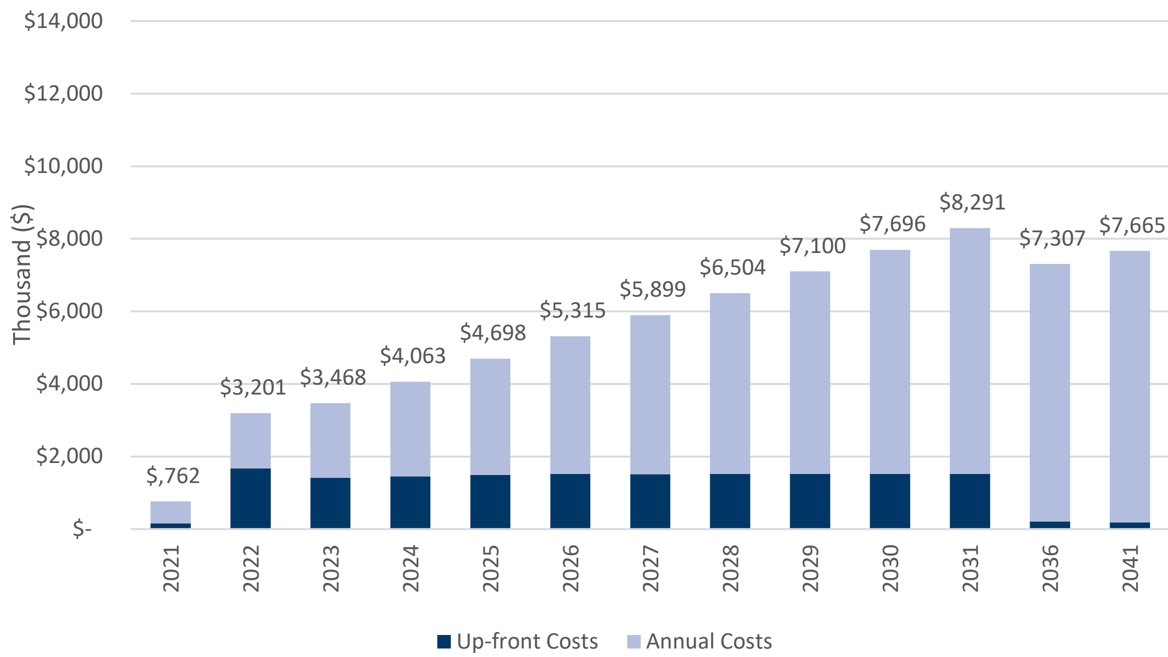
Figure 7 and Figure 8 below provide the program costs for mechanical solutions, broken down by upfront measure costs[10], and program administration costs and customer incentives. The set of mechanical solutions measures are constant throughout all scenarios. The results show higher up-front costs in the initial development years as new programs are developed, new customers are enrolled in the programs and new controls systems are put in place.

Figure 7 – DEC Mechanical Solutions Costs



[10] Upfront measure costs include sign-up (enrollment) incentive costs, as well as controls and equipment installation costs.

Figure 8 – DEP Mechanical Solutions Costs



The Utility Cost Test (UCT) results assume that participants will stay enroll for 10 or 11 years, depending on the expected measure life. Table 8 provides cost-effectiveness results based on a program lifetime basis.

Table 8 – DEC Demand Response UCT Results

Programs	Measure/Program Life	UCT (at full deployment - 2026)
Residential Rate-Enabled T-Stat	11	3.2
Residential BYOT	4	4.9
Residential Rate-Enabled HWH	11	1.3
WP/HP Tune-up	10	2.0
Commercial Rate-Enabled T-Stat	10	2.7
Commercial BYOT	4	3.6
Residential BYOB	10	0.5
ADR	10	4.1

Table 9 – DEP Demand Response UCT Results

Programs	Measure/Program Life	UCT (at full deployment - 2026)
Residential Rate-Enabled T-Stat	11	2.3
Residential BYOT	4	3.7
Residential Rate-Enabled HWH	11	1.0
WP/HP Tune-up	10	1.2
Commercial Rate-Enabled T-Stat	10	1.6
Commercial BYOT	4	2.2
Residential BYOB	10	0.3
ADR	10	2.8

All modelled measures were cost-effective on a lifetime basis except for residential battery energy storage. This measure is cost-effective at measure level but fails the test at program level due to the costs required for running the program (fixed program costs) because it is assumed that there are a small number of residential battery systems currently installed among Duke's residential customers.

The impacts assessed for each scenario on the standard winter peak day in 2031 are shown in Figure 9 and Figure 10, where all programs are at full deployment. The assessment reveals that the combined impacts of the DSM rates and measures are not sufficient to alter the timing of the winter peak on the standard peak day. Thus, the net potential, is assessed as the achieved load reduction at the identified peak hours. For DEC, the load is nearly flat from 7:00 to 8:59, emphasizing the importance to target not only the peak hour, but the whole peak.[11]

[11] Our definition of peak did not consider wholesale transactions because the EE and DSM programs included in the solution set will not be available to this market

Figure 9 – DEC: Scenario Impact on Peak Day Load Shape (2031)

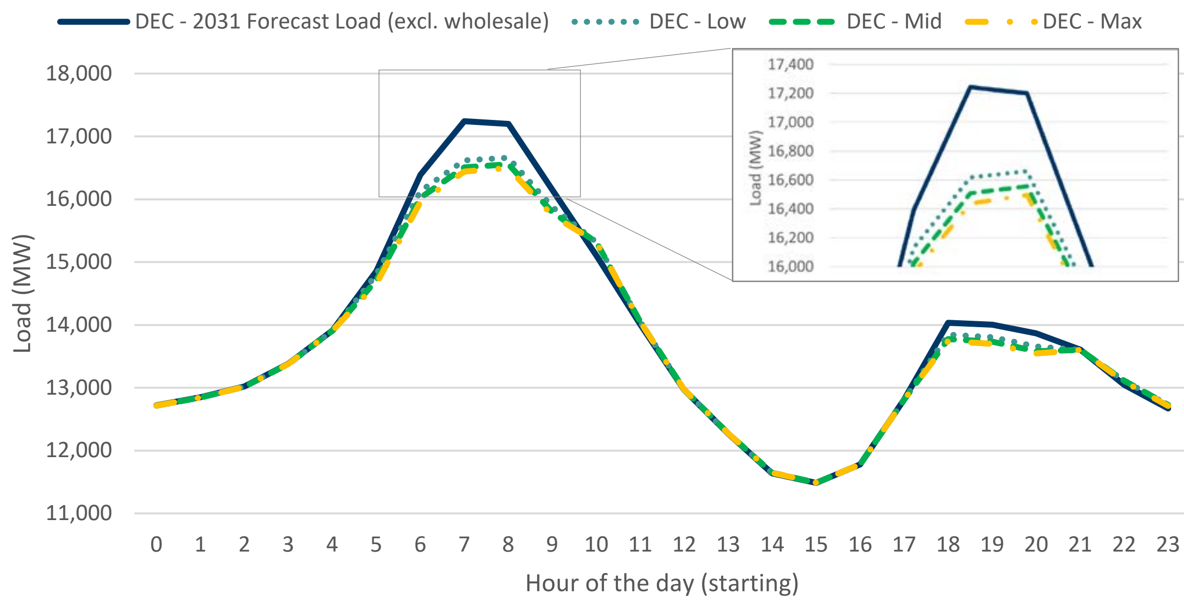
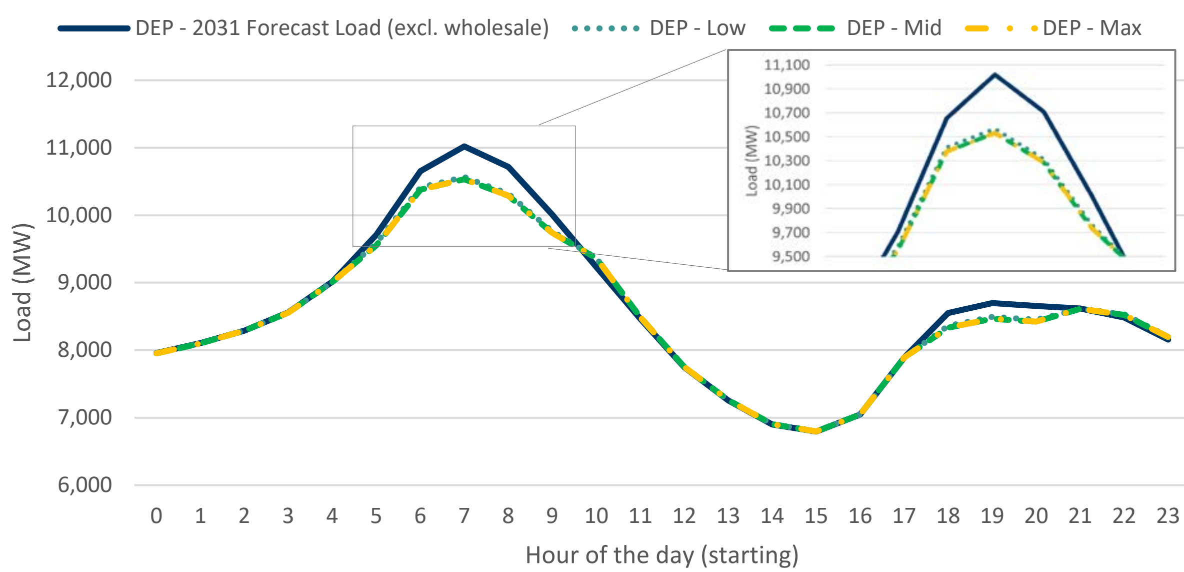


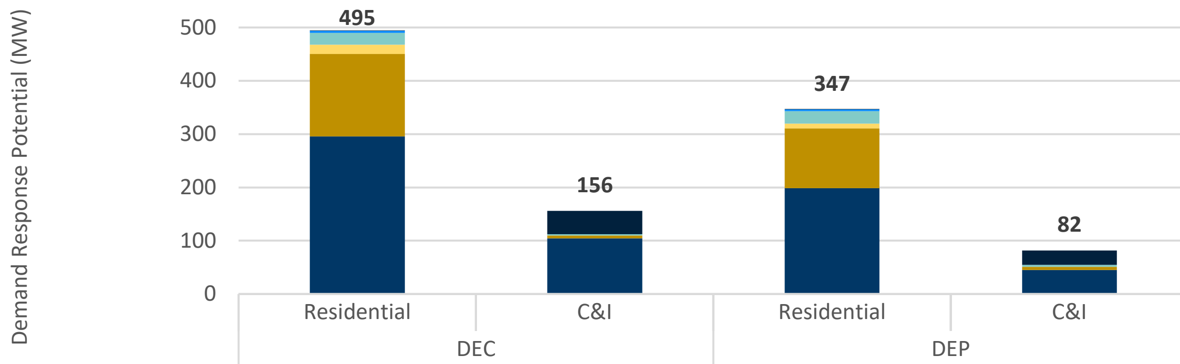
Figure 10 – DEP: Scenario Impact on Peak Day Load Shape (2031)



3.1 LOW SCENARIO

The Low scenario captures the DSM potential from two DSM rates options evaluated under the Flex Savings Options Pilot: TOU and TOU+CPP, in combination with the proposed set of mechanical solutions, thereby assessing rates that can be relatively quickly deployed. Figure 11 shows that DEC and DEP can respectively achieve 651 MW and 428 MW in winter peak reductions by 2041. Overall, the rate solutions and the residential Bring Your Own Thermostat (BYOT) program together account for more than 80% of the DSM potential.

Figure 11 – Low Scenario Achievable DSM Potential (2041) *



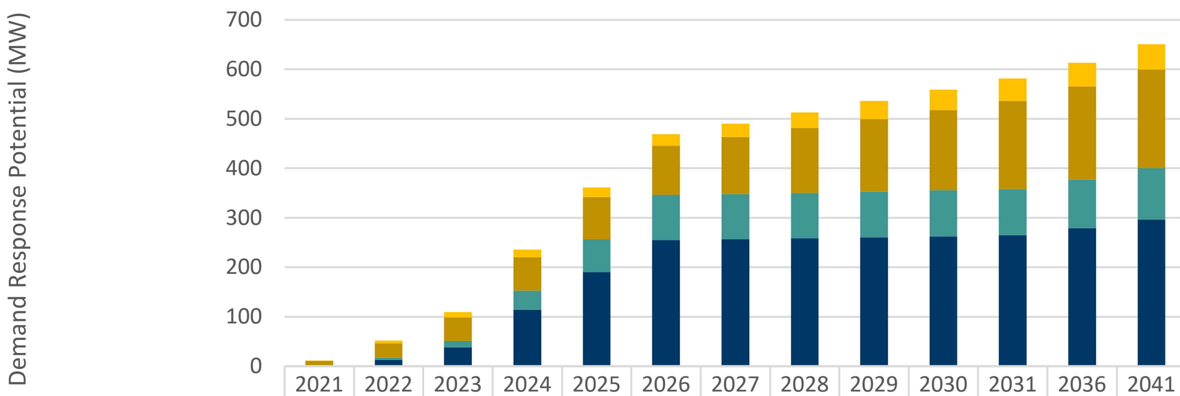
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	495	156	347	82
ADR		43		27
Battery Storage	0.4		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	22	3	23	3
Rate-enabled HWH	17		9	
BYOT	154	5	112	6
Rate Solution	296	105	199	45

* Due to rounding, numbers may not add up

Reviewing of the above chart, along with the detailed results provided in the appendix, a range of observations to focus on become apparent regarding future opportunities for Duke DSM programs. Although the TOU+CPP rate option accounts for 60% of the customer enrollment, it composed about 85% of the residential DSM rate savings, providing significantly more savings per customer than TOU. High savings from TOU+CPP participants are consistent with the preliminary results from the Flex Savings Options Pilot. Rate-enabled solutions, for both thermostats and water heaters account for a further 7% for the savings, reaching 72 MW in 2041. The residential BYOT program is already offered for summer peak reduction purposes and is in-process of being expanded to the winter season, offering an immediate expansion of winter peak reductions until new DSM rates can be successfully deployed.

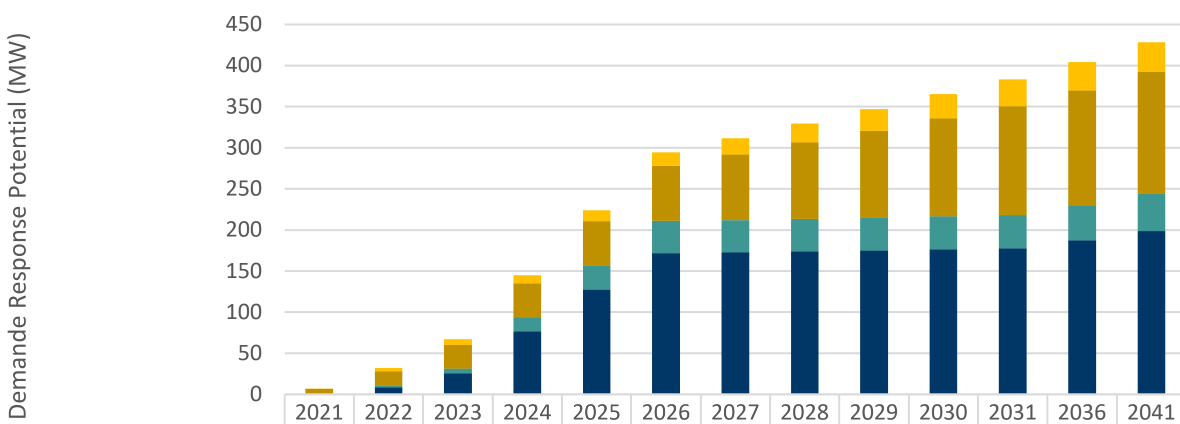
Figure 12 and Figure 13 below present the DSM solution ramp-up from 2021 to 2031, where all programs are at full deployment. The programs then continue to scale with load growth until 2041.

Figure 12 – DEC - Low Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	1	6	11	16	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	29	47	67	85	99	115	131	146	162	178	188	199
C&I - Rates	0.0	4.3	12.9	38.8	66.3	91.3	91.6	92.1	92.7	93.0	93.5	98.6	104.6
Residential - Rates	0	13	38	114	190	255	256	258	260	262	265	279	296

Figure 13 – DEP - Low Scenario Deployment

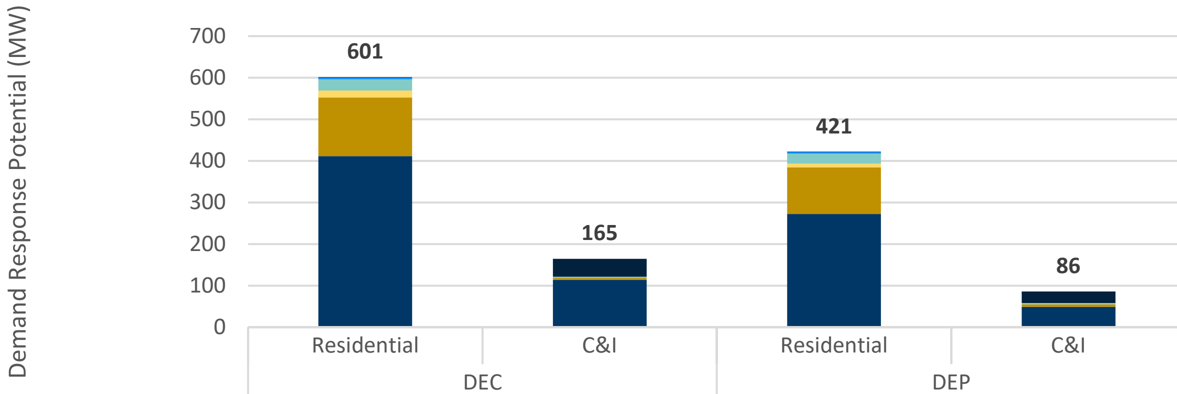


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	80	93	106	119	132	140	148
C&I - Rates	0.0	1.9	5.8	17.5	29.3	39.2	39.3	39.5	39.6	40.3	40.5	42.7	45.2
Residential - Rates	0	8	25	77	128	172	173	174	175	176	178	187	199

3.2 MID SCENARIO

The Mid scenario includes the DSM potential from the Low scenario, while adding a new residential rate option (Bill certainty with PTR) which targets risk averse customers. Adoption from small C&I is also increased, while PTR incentives for medium and large customers are doubled to $60/kW. Figure 14 below shows the breakdown of savings from the Mid scenario, wherein the overall achievable potentials for DEC and DEP in 2041 are 766 MW and 507 MW, respectively. With the addition of a new residential rate, rate solutions (residential and C&I) and BYOT now collectively account for over 85% of the DSM potential.

Figure 14 – Mid Scenario Demand Response Potential (2041) *



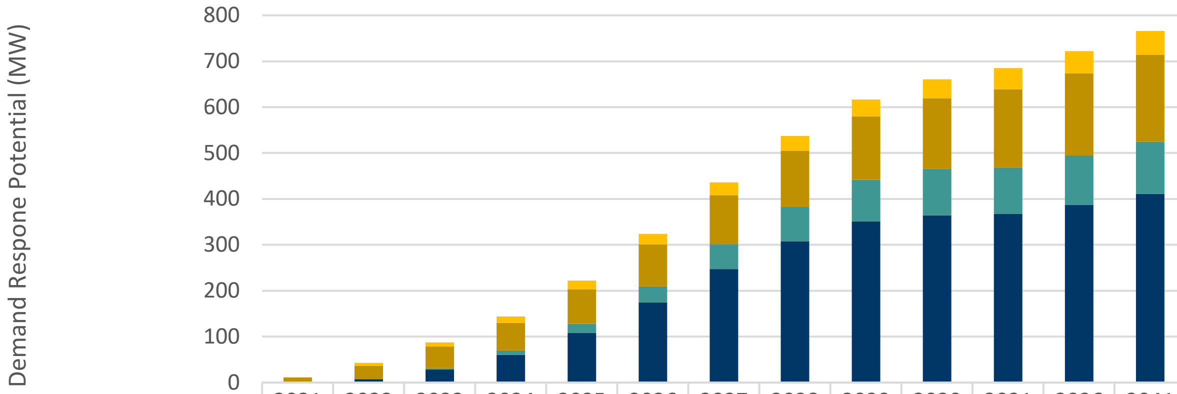
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	601	165	421	86
ADR		43		27
Battery Storage	0.5		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	27	3	24	3
Rate-enabled HWH	17		9	
BYOT	141	5	112	6
Rate Solution	411	113	272	49

* Due to rounding, numbers may not add up

The new Bill certainty with PTR rate option, accounts for a little under 30% of the residential rate savings potential and for most of the additional potential under residential rate solution in the Mid scenario. Despite the increase to the potential for the small C&I segment (i.e., from 9.0 MW in the Low scenario to 13.4 MW in the Mid scenario), overall, it has a limited impact on the total potential, which may not make this market segment a strong candidate for short-term program expansion. Finally, doubling the incentives to $60/kW for the medium and large C&I PTR program has limited impact, increasing the PTR potential by just 10%, while program costs increased by over 80%.

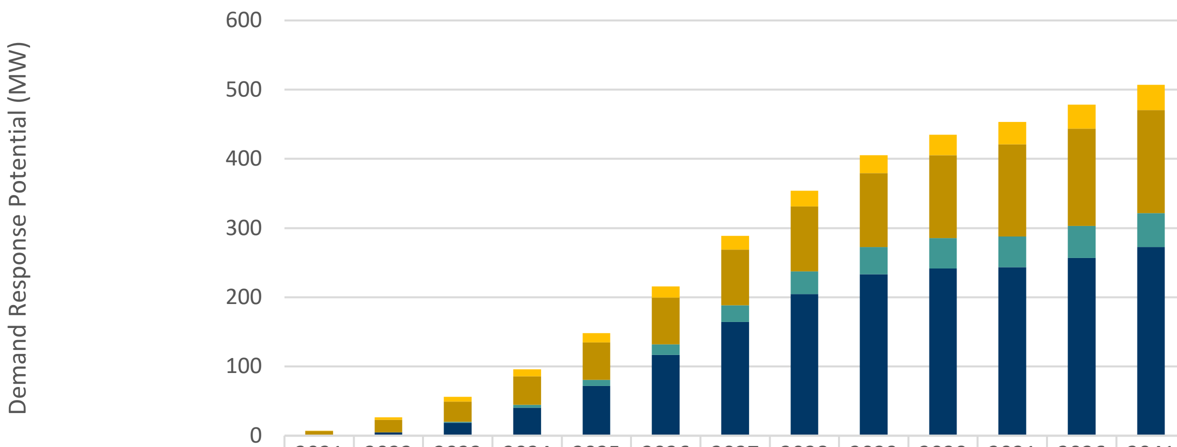
Figure 15 and Figure 16 below present the annual achievable potential, from 2021 to 2041. Program roll-out is extended compared to the Low scenario, to account for the time needed to implement the new rate option.

Figure 15 – DEC - Mid Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	1	6	9	14	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	29	47	60	75	91	107	123	138	154	170	179	190
C&I - Rates	0.0	0.0	2.9	9.8	19.7	34.6	54.7	74.9	90.4	101.0	101.4	106.9	113.4
Residential - Rates	0	8	28	61	109	175	247	308	351	364	368	388	411

Figure 16 – DEP - Mid Scenario Deployment

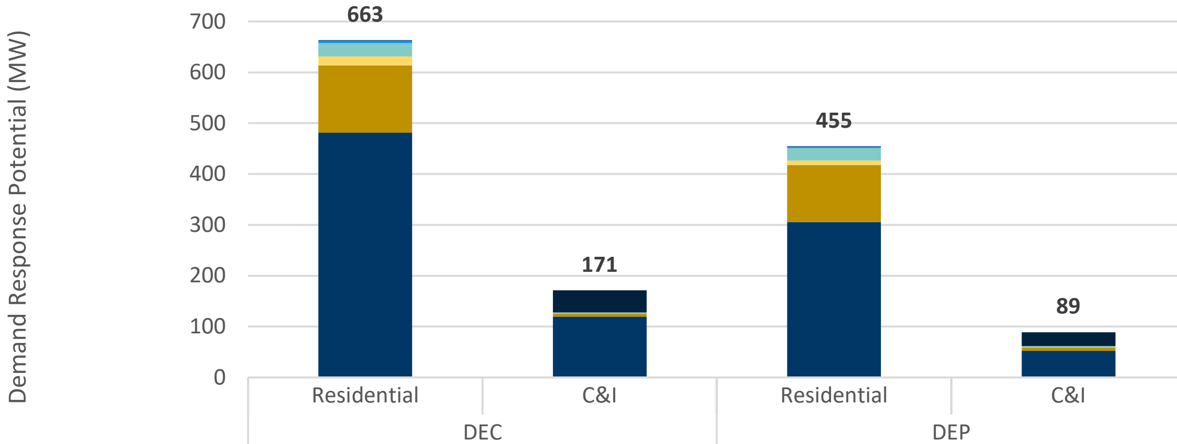


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	81	94	107	120	133	140	149
C&I - Rates	0.0	0.0	1.3	4.3	8.6	15.1	23.8	32.6	39.3	43.9	44.0	46.4	49.2
Residential - Rates	0	5	19	40	72	117	165	205	233	242	244	257	272

3.3 MAX SCENARIO

The Max scenario aims to maximize the DSM rates potentials, and to assess the impact of offering the highest possible PTR incentives. A new CPP with flat volumetric rate is added to complement the residential rates included in the Mid scenario. In the Max scenario a complete set of residential rates options is offered ranging from low risk (Bill certainty with PTR) to high risk (TOU+CPP). In the C&I sector, the small C&I adoption was raised while incentives for medium and large C&I PTR were raised to their maximum level, while maintaining program cost-effectiveness. Figure 17 shows that DEC and DEP can respectively achieve 834 MW and 544 MW by 2041. With the addition of another new residential rate, collectively the rate solutions (residential and C&I) and BYOT now account for over 87% of the DSM potential.

Figure 17 – Max Scenario Demand Response Potential (2041) *



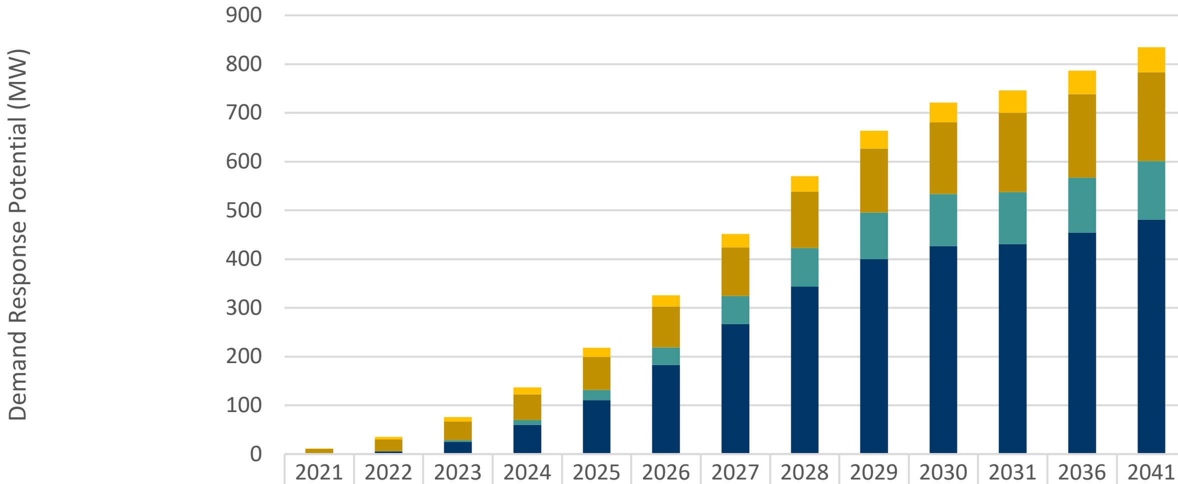
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	663	171	455	89
ADR		43		27
Battery Storage	0.5		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	27	3	24	3
Rate-enabled HWH	17		9	
BYOT	133	5	112	6
Rate Solution	481	120	306	53

* Due to rounding, numbers may not add up

Like the Mid scenario findings, the increase in adoption among small C&I customers and the increase in PTR incentives for the medium and large C&I customers resulted in limited additional uptake. The C&I sector potential reaches just 265 MW under the Max scenario (DEC and DEP combined) compared to the 241 MW in the Low scenario. The Max scenario residential rate potential presents a 39% increase over the Low scenario and a 17% increase compared to the Mid scenario. The breakdown of savings among the DSM rates is similar for both DEC and DE, with the TOU+CPP rate and Bill certainty with PTR each accounting for over 30% of the overall DSM rates savings.

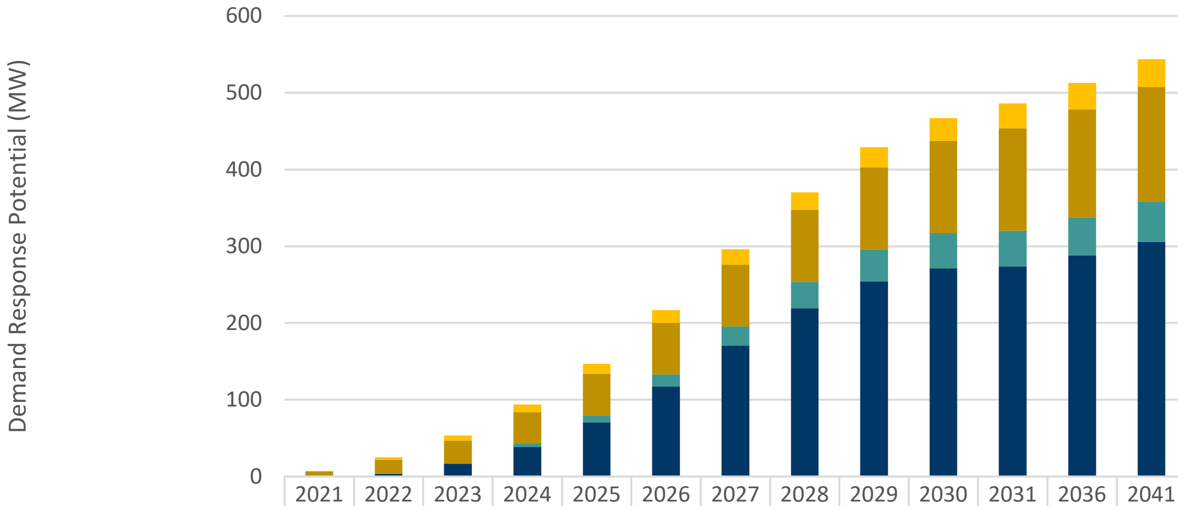
Figure 18 and Figure 19 below present the in each year from 2021 to 2041. As for the Mid scenario, program roll-out is extended to allow for the time needed to deploy additional new rate options.

Figure 18 – DEC - Max Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	5	9	14	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	25	38	52	68	84	100	115	131	147	163	171	182
C&I - Rates	0	0	3	10	21	37	58	79	95	107	107	113	120
Residential - Rates	0	6	25	60	111	183	267	343	400	427	430	454	481

Figure 19 – DEP - Max Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	81	94	107	120	133	140	149
C&I - Rates	0	0	1	5	9	16	25	34	41	46	47	50	53
Residential - Rates	0	4	16	38	70	117	170	219	255	271	273	288	306

3.4 COMPARISON WITH DUKE'S MARKET POTENTIAL STUDY (MPS)

The goal of this study is to assess possible strategies that could allow Duke Energy to expand its winter peak reduction potential. To that end, it focuses on a small set of specific mechanical and rates solutions specifically selected for their ability to address winter peak loads. It is important to note that the study does not include all available mechanical solutions and therefore differs from the MPS conducted by

Nexant. Conversely, the MPS study focused on the achievable potential related to all mechanical solutions and did not assess any rate structure impacts.

Table 10 and Table 11 below show a high-level comparison between the MPS[12],[13] results and the modelled solution set. In both studies, the DSM potentials assessed are incremental to Duke's current winter peak DSM program impacts.

Table 10: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEC)

	DEC - 2041 Max Scenario	MPS – DEC (Base – 2041)	MPS – DEC (Enhanced – 2041)
Potential Total (MW)	**834**	**403**	**488**
C&I	Rates: 120 Mechanical: 51	38	69
Residential	Rates: 481	0	0
	Mechanical: 182	365	419

Table 11: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEP)

	DEP - 2041 Max Scenario	MPS – DEP (Base – 2041)	MPS – DEP (Enhanced – 2041)
Potential Total (MW)	**544**	**273**	**307**
C&I	Rates: 53 Mechanical: 36	3	5
Residential	Rates: 306	0	0
	Mechanical: 149	270	302

For the C&I market, this study estimates rate and mechanical potential separately and shows the impact mechanical solutions and rates not considered in the MPS and are therefore incremental to that study. For the residential sector, the potential in this study is also incremental to the MPS and outlines a plan to operationalize a more specific set of high value technologies and new rates not considered in the MPS. Additionally, the MPS excluded DSM rider opt-out customers while this study considers that a PTR rate structure could potentially attract some of those customers (between 5% and 9% depending on the rate class and scenario).

[12] DEC values are from is Duke Energy North Carolina EE and DSM Market Potential Study, May 2020, Figure 7-21 DEC DSM Winter Peak Capacity Program Potential and Duke Energy South Carolina EE and DSM Market Potential Study, April 2020. Figure 7-20 DEC DSM Summer Peak Capacity Program Potential

[13] DEP values are from is Duke Energy North Carolina EE and DSM Market Potential Study, May 2020, Figure 7-23 DEP DSM Winter Peak Capacity Program Potential and Duke Energy South Carolina EE and DSM Market Potential Study, April 2020. Figure 7-23 DEP DSM Summer Peak Capacity Program Potential

4 KEY TAKE-AWAYS

Based on the results of the winter peak demand reduction potential assessment, there is an apparent 1,378 MW (Max Scenario –DEC and DEP combined) of winter season DSM potential by 2041 representing 4.3% and 4.4% of the DEC and DEP forecasted load, respectively.

As shown in Table 12, most of this potential can be achieved via the residential sector using new rates and expanding mechanical solutions. A smaller portion of the DSM potential can be achieved by increasing incentives to drive program adoption and by diversifying rate structures.

Table 12 – Achievable DSM Potential in 2041, by Scenario (MW)

	Low Scenario	Mid Scenario	Max Scenario
Total Achievable Potential	**1,079 MW**	**1,273 MW**	**1,378 MW**
DEC Achievable Potential	651 MW (495 Res/156 C&I)	766 MW (601 Res/165 C&I)	834 MW (663 Res/171 C&I)
DEP Achievable Potential	428 MW (347 Res/82 C&I)	507 MW (421 Res/86 C&I)	544 MW (455 Res/89 C&I)

Table 13 below benchmarks the achievable DSM potential from the Mid and Max scenarios to DSM potential study findings in other jurisdictions. Overall, these show that the Duke DSM potential is like other winter peaking jurisdictions, where the industrial portion of the utility peak load is moderate and avoided costs are low, as is the case for Duke Energy.

Table 13 – Benchmarking of the Achievable DSM Potential (Mid-Max Scenarios) to Winter Peaking Jurisdictions

	Duke Energy (2020)	Newfoundland and Labrador (2019)	Puget Sound Energy (2017)	Northwest Power & Cons. Council (2014)
Portion of Peak Load	DEC: 4.0% - 4.3% DEP: 4.1% - 4.4% (2041)	10.4%[14] (15-year outlook)	3.7% (20-year outlook)	8.8% (15-year outlook)

Based on the findings in this report three key take-aways emerge:

- **Residential sector programs are key to achieve significant winter demand reduction potentials.** Across all scenarios, the residential sector shows three to four times more potential than the C&I

[14] The share of curtailable industrial load contributing to the utility peak load in Newfoundland and Labrador is high.

sector. This is driven primarily by seasonal variation in the residential sector demand curves, which results from the relatively high penetration of electric heating in the residential sector, while the C&I sector exhibits flatter variations on a daily and inter-seasonal basis.

Duke's current winter residential DSM offering is limited to DEP NC in the Company's Western Region service territory in the area surrounding Asheville[15] and the results of this study indicate that there is potential to expand residential Duke's winter DSM programs. Residential savings are derived from both mechanical and DSM rate solutions, and will likely take time to implement, in some cases requiring regulatory approval for new rates and pilots and programs.

- **Duke should consider pursuing some quick wins in the immediate term, followed by the addition of more complex and varied rate options.**

  On the residential side, a winter BYOT program can likely be implemented as the lowest-hanging fruit option, by adapting the existing summer peak BYOT program to include winter peak events.

  Following that, TOU and TOU+CPP rate designs could be implemented, pending positive results from the Flex Savings Options Pilot conclusions. Bill certainty + PTR and a Flat volumetric + CPP rate option can also be developed as near-term options to capture residential winter peak reduction potential.

  On the C&I side, implementing a PTR rate structure can achieve higher potential reduction than adding other new DSM programs. As a second step, adding Automated Demand Response solutions could enhance current DSM programs.

- **Changes to PTR incentive levels have very little impact on medium and large C&I customer potentials.** Most of the achievable DSM potential (91%) for medium and large customers is achievable with the low scenario incentives ($30 per kW).

Overall, it appears that expanding to new programs and rates could have an important role in increasing Duke winter peak DSM potential in both the DEC and DEP systems.

[15] This program, funded through Rider LC-WIN-2B, installs controls to (1) interrupt service to all resistance heating elements installed in approved central electric heat pump units with strip heat and/or (2) interrupt service to each installed, approved electric water heater. In addition, a winter BYOT filing has been made but has not yet been operationalized as of the time of this study being published

A.1 RESULTS BREAKDOWN BY RATE CLASS

Table A-1 – Scenario 1 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	3	9	15	21	21	21	21	21	21	22	22	22	22	22	23	23	23	24	24
			TOU+CPP - Res	0	7	22	67	112	151	152	153	154	155	156	158	159	161	163	165	167	169	171	173	175
		Businesses	PTR - SGS	0.0	0.1	0.4	1.2	2.0	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0
			PTR - Medium and Large C&I	0	2	5	16	27	37	37	37	37	38	38	38	38	39	39	40	40	41	41	42	42
	DEC	Residential	TOU - RE	0	2	5	15	25	33	34	34	34	34	35	35	35	36	36	37	37	37	38	38	39
			TOU+CPP - RE	0	7	21	64	106	142	143	144	145	146	148	149	150	152	154	156	157	159	161	163	165
			TOU - RS	0.0	0.3	0.9	2.7	4.5	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.8	6.9	7.0
			TOU+CPP - RS	0	4	11	33	55	73	74	74	75	75	76	77	78	78	79	80	81	82	83	84	85
		Businesses	PTR - SGS	0.0	0.3	0.8	2.3	3.8	5.1	5.1	5.2	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			PTR - Medium and Large C&I	0	4	12	37	62	86	86	87	87	88	88	89	90	91	92	93	94	95	96	98	99
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	12	14	16	19	21	21	21	21	22	22	22	22	23	23	23
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	3	6	9	10	9	12	14	16	18	20	20	20	20	21	21	21	21	22	22	22
			Res. Wi-Fi T-Stat	11	23	37	51	67	80	91	103	115	126	138	139	141	142	144	146	147	149	151	153	154
			Res. HP Tune-up	0	1.6	2.0	2.4	2.7	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.2	2.5	3.8	5.2	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
		Businesses	Comm. Rate-Enabled T-Stat	0	0.7	1.1	1.5	1.8	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.6	1.3	2.0	2.7	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

Table A-2 – Scenario 2 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	2	4	7	11	16	19	21	21	21	22	22	22	22	22	23	23	23	24	24
			TOU+CPP - Res	0	4	15	30	52	83	114	138	154	155	156	158	159	161	163	165	167	169	171	173	175
			Bill Certainty + PTR - Res	0	0	2	6	13	22	35	48	58	65	66	66	67	68	69	69	70	71	72	73	74
		Businesses	Bill Certainty + PTR - SGS	0.0	0.0	0.1	0.4	0.8	1.4	2.2	3.0	3.6	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6
			PTR - Medium and Large C&I	0	0	1	4	8	14	22	30	36	40	40	40	41	41	42	42	43	43	44	44	45
	DEC	Residential	TOU - RE	0	1	3	7	12	18	25	30	34	34	35	35	35	36	36	37	37	37	38	38	39
			TOU+CPP - RE	0	4	14	28	50	78	107	130	145	146	148	149	150	152	154	156	157	159	161	163	165
			Bill Certainty + PTR - RE	0	0	2	8	15	27	43	59	71	80	80	81	82	83	84	85	86	87	88	89	90
			TOU - RS	0.0	0.2	0.6	1.2	2.1	3.3	4.5	5.5	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.8	6.9	7.0
			TOU+CPP - RS	0	2	7	15	26	40	55	67	75	75	76	77	78	78	79	80	81	82	83	84	85
			Bill Certainty + PTR - RS	0	0	1	2	4	8	12	17	20	22	23	23	23	23	24	24	24	24	25	25	25
		Businesses	PTR - SGS	0.0	0.0	0.2	0.8	1.5	2.7	4.2	5.8	7.0	7.9	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9
			PTR - Medium and Large C&I	0	0	3	9	18	32	51	69	83	93	93	94	95	96	97	99	100	101	102	103	104
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	13	15	17	19	22	22	22	22	22	23	23	23	24	24	24
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	3	6	7	9	11	14	16	19	21	24	24	24	25	25	25	26	26	26	27	27
			Res. Wi-Fi T-Stat	11	23	36	46	58	69	81	92	103	115	126	127	128	130	131	133	135	136	138	140	141
			Res. HP Tune-up	0	1.6	1.6	1.9	2.3	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.2	2.9	4.4	6.0	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
		Businesses	Comm. Rate-Enabled T-Stat	0	0.7	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.6	1.3	1.1	1.5	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

Table A-3 – Scenario 3 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	3	6	10	16	23	27	30	31	31	31	31	32	32	33	33	33	34	34	35
			TOU+CPP - Res	0	3	9	18	32	51	69	84	94	95	95	96	97	98	99	101	102	103	104	106	107
			Bill Certainty + PTR - Res	0	0	2	8	16	27	43	59	72	80	81	82	83	83	84	85	86	87	89	90	91
			Flat Volumetric + CPP - Res	0	0	2	6	13	22	35	48	58	65	66	67	67	68	69	70	70	71	72	73	74
		Businesses	Bill Certainty + PTR - SGS	0.0	0.0	0.2	0.5	1.0	1.8	2.9	4.0	4.8	5.4	5.4	5.5	5.5	5.6	5.7	5.7	5.8	5.9	6.0	6.0	6.1
			PTR - Medium and Large C&I	0	0	1	4	8	14	22	30	37	41	42	42	42	43	43	44	44	45	45	46	46
	DEC	Residential	TOU - RE	0	1	4	9	15	24	33	39	44	44	45	45	46	46	47	47	48	48	49	50	50
			TOU+CPP - RE	0	3	9	18	32	51	70	84	94	95	96	97	98	99	100	101	102	104	105	106	107
			Bill Certainty + PTR - RE	0	0	3	10	19	34	53	73	89	100	100	101	102	103	105	106	107	108	110	111	112
			Flat Volumetric + CPP - RE	0	0	3	8	17	30	47	64	78	87	88	89	90	91	92	93	94	95	96	98	99
			TOU - RS	0.0	0.2	0.6	1.3	2.3	3.6	4.9	5.9	6.6	6.7	6.7	6.8	6.9	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.5
			TOU+CPP - RS	0	1	4	9	16	25	34	41	46	46	46	47	47	48	48	49	50	50	51	51	52
			Bill Certainty + PTR - RS	0	0	1	3	6	10	16	21	26	29	29	30	30	30	31	31	31	32	32	32	33
			Flat Volumetric + CPP - RS	0	0	1	2	4	6	10	14	16	18	19	19	19	19	19	20	20	20	20	21	21
		Businesses	PTR - SGS	0.0	0.0	0.3	1.0	2.0	3.6	5.6	7.7	9.4	10.5	10.6	10.7	10.8	10.9	11.0	11.2	11.3	11.4	11.6	11.7	11.8
			PTR - Medium and Large C&I	0	0	3	9	19	33	52	72	86	96	97	98	98	100	101	102	103	104	106	107	108
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	13	15	17	19	22	22	22	22	22	23	23	23	24	24	24
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	2	4	7	9	11	14	16	19	21	24	24	24	25	25	25	26	26	26	27	27
			Res. Wi-Fi T-Stat	11	19	29	39	51	62	73	85	96	107	119	120	121	122	123	125	126	128	130	131	133
			Res. HP Tune-up	0	1.3	1.6	1.9	2.3	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.4	2.9	4.4	6.0	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.3	0.7	1.1	1.5	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

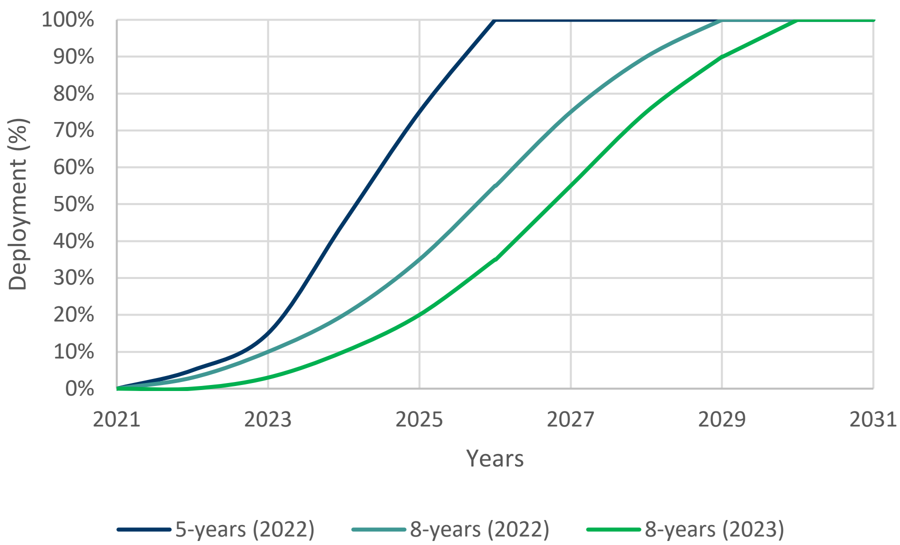
A.2 PROGRAM RAMP-UP AND COSTS

RAMP-UP

Ramp-up rates were created using s-curves over 5 and 8 years.

The low scenario, which is easier to implement, includes a ramp-up over 5 years. Scenarios Mid and Max, which requires more rates designs, assume a ramp-up over 8 years before full deployment of the rate solutions. Furthermore, rates that where included in the pilot (TOU and TOU+CPP) are estimated to launch in 2022, while bill certainty + PTR and flat volumetric + CPP are starting in 2023. The figure below summarized the ramp-up.

Figure A-1 – Enrollment Ramp-up: Rates



PROGRAM COSTS

Estimated program costs for the mechanical solution set are presented in the table below.

Table A-4: Program Costs

Program Name	Development Costs	Program Fixed Annual Costs	Other Costs ($/customers) for marketing, IT, admin
Residential Rate-Enabled T-Stat	$200,000	$100,000	$40
Residential BYOT	$100,000	$100,000	$40
Residential Rate-Enabled HWH	$175,000	$75,000	$35
WP/HP Tune-up	$175,000	$100,000	$0
Commercial Rate-Enabled T-Stat	$150,000	$75,000	$40
Commercial BYOT	$75,000	$75,000	$40
Residential BYOB	$100,000	$100,000	$30
ADR	$250,000	$150,000	$20

A.3 KEY ASSUMPTIONS

ECONOMIC ASSUMPTIONS

The avoided costs provided by Dukes for South and North Carolina were blended between South and North Carolinas to obtain an average avoided cost for each system. These avoided costs are presented in the table below, in 2021 dollars. This study uses also uses blended discount rates of 6.9% (DEC) and 6.8% (DEP).

Table A-5 – Avoided Costs

Year	DEC - Avoided cost ($/kW)	DEP - Avoided cost ($/kW)
2021	129.5	100.6
2022	131.6	102.1
2023	133.9	103.8
2024	136.3	105.5
2025	138.8	107.2
2026	141.3	108.9
2027	144.0	110.8
2028	146.7	112.6
2029	149.5	114.5
2030	152.3	116.5
2031	155.1	118.4
2032	157.9	120.3
2033	160.7	122.3
2034	163.6	124.3
2035	166.5	126.3
2036	169.5	128.3
2037	172.5	130.4
2038	175.6	132.5
2039	178.8	134.7
2040	182.0	136.9
2041	185.3	139.1
2042	188.6	141.4
2043	192.1	143.8
2044	195.5	146.1
2045	199.1	148.5

SEGMENTATION AND END USE

The follow ratios where used to breakdown the potential by State.

Table A-6 – Segmentation by State

State	DEC	DEP
North Carolina	73.50%	85%
South Carolina	26.50%	15%

To obtain a breakdown per rate and per end use, the latest EIA's CBECS (2012) and RECS (2015) data was used. This data was combined with Duke's 2017 and 2018 annual consumption and average consumption per customer for each rate class to obtain the following tables.

Table A-7 – DEC segmentation assumptions

Segment	Share of Primary Space Heating Electric (%)	Share of Primary Hot Water Electric (%)	Average Annual Consumption (kWh)	Population
SGS	64%	78%	18,049	324,972
LGS	64%	78%	536,989	11,431
OPTC	64%	78%	745,677	21,133
OPTI	64%	78%	11,394,026	1,642
Other	64%	78%	412,306	7005
RS	24%	52%	12,866	1,295,393
RE	100%	100%	13,485	946,860

Table A-8 – DEP segmentation assumptions

Segment	Share of Primary Space Heating Electric (%)	Share of Primary Hot Water Electric (%)	Average Annual Consumption (kWh)	Population
SGS	64%	78%	14,379	201,554
MGS	64%	78%	372,588	33,267
LGS	64%	78%	17,371,855	255
RTP	64%	78%	68,103,493	90
Other	64%	78%	62,518	1159.44
Res	63%	72%	13,951	1,322,187

The EIA's building archetypes where used to generate 8760h annual load curve to model consumption for each rate class.

Table A-9 – DEC building archetypes included per rates

EIA's Archetypes	Segment						
	RS	RE	SGS	LGS	OPTC	OPTI	Other
Hospital	-	-	-	Yes	Yes	Yes	Yes
Hotel Small	-	-	Yes	-	-	-	-
Industrial	-	-	-	Yes	Yes	Yes	Yes
MF_Elec. Resistance	Yes	Yes	-	-	-	-	-
MF_HP	Yes	Yes	-	-	-	-	-
Office Large	-	-	-	Yes	Yes	Yes	Yes
Office Medium	-	-	Yes	Yes	Yes	Yes	Yes
Office Small	-	-	Yes	-	-	-	-
Outpatient Healthcare	-	-	Yes	-	-	-	-
Restaurant Fast Food	-	-	Yes	-	-	-	-
Restaurant Sit Down	-	-	Yes	-	-	-	-
Retail Standalone	-	-	Yes	-	-	-	-
Retail Strip Mall	-	-	Yes	-	-	-	-
School Primary		-	-	Yes	Yes	Yes	Yes
School Secondary	-	-	-	Yes	Yes	Yes	Yes
SF_Elec. Resistance	Yes	Yes	-	-	-	-	-
SF_HP	Yes	Yes	-	-	-	-	-
Supermarket	-	-	-	Yes	Yes	Yes	Yes
Warehouse	-	-	Yes	Yes	Yes	Yes	Yes

Table A-10 – DEP building archetypes included per rates

EIA's Archetypes	Segment					
	Res	SGS	MGS	LGS	RTP	Other
Hospital	-	-	Yes	Yes	Yes	Yes
Hotel Small	-	Yes	Yes	-	-	-
Industrial	-	-	-	Yes	Yes	Yes
MF_Elec. Resistance	Yes	-	-	-	-	-
MF_HP	Yes	-	-	-	-	-
Office Large	-	-	-	Yes	Yes	Yes
Office Medium	-	Yes	Yes	Yes	Yes	Yes
Office Small	-	Yes	-	-	-	-
Outpatient Healthcare	-	Yes	Yes	-	-	-
Restaurant Fast Food	-	Yes	Yes	-	-	-
Restaurant Sit Down	-	Yes	Yes	-	-	-
Retail Standalone	-	Yes	-	-	-	-
Retail Strip Mall	-	Yes	-	-	-	-
School Primary		-	Yes	Yes	-	Yes
School Secondary	-	-	Yes	Yes	-	Yes
SF_Elec. Resistance	Yes	-	-	-	-	-
SF_HP	Yes	-	-	-	-	-
Supermarket	-	-	Yes	Yes	Yes	Yes
Warehouse	-	Yes	Yes	Yes	Yes	Yes

RESIDENTIAL RATE DETAILS

TOU RATES

This rate targets consumers able to vary their daily usage to reduce energy costs. This new TOU structure is based on the Flex Savings Options pilot conducted by Nexant for Duke Energy Carolinas (NC). The pilot went into effect on October 1, 2019 and preliminary results were provided by Duke to inform our analysis. The pilot tested three different rates structures (TOU, CPP, TOUD) across three customer classes including all-electric residential (RE) and standard residential (RS).

- **Peak to off-peak ratio:** 1.7
- **Peak load impact**
  - Based on preliminary Flex Savings Options Pilot findings
  - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

TOU WITH CPP

This rate targets consumers who are highly attentive to their energy demand and can change their load in a significant manner. The modelled TOU with CPP rate structure is also based on the Flex Savings Options Pilot. Customers are on the previous TOU rate but with higher hourly prices during specific peak hours on about 20 days per year.

- **CPP Peak to off-peak ratios:** 3.2
- **Peak load impact**
  - Based on the preliminary Flex Savings Options Pilot findings
  - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

BILL CERTAINTY WITH PTR

This rate targets consumers who want to mitigate their billing risk. It offers a fixed bill per month, with a PTR on peak days.

- **Peak to off-peak ratios**
  - 3:1 savings ratio for all rates[16]
  - Bill certainty is not expected to increase the winter peak demand compared to a flat volumetric rate
- **Peak load impact**
  - Peak impact reduction was derived from the Arcturus[17] analysis on dynamic rates. This analysis evaluates the customer peak reduction to dynamic rates, covering more than 300 pricing treatments from over 60 pilots.

---

[16] For example: With an average cost of electricity over the fixed bill is 15¢/kWh, the rebate would be 30¢/kWh, for a total discount of 45¢/kWh, which is three times to initial cost of electricity.

[17] Peak reduction from "Arcturus 2.0: A meta-analysis of time-varying rates for electricity", A. Faruqui, S. Sergici and C. Warner, 2017.

- Bounce back effects are derived from the Flex Savings Options Pilot findings (CPP), adjusted for savings.
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

FLAT VOLUMETRIC WITH CPP

This rate targets consumers who can change their load in a significant manner but are not willing to modify their everyday usage. It offers a fixed price per unit of energy consumed, with a CPP on peak days.

- **CPP peak to off-peak ratios:** 5.5
- **Peak load impact**
  - Based on the Flex Savings Options Pilot findings
  - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

It is important to note that all customers who are enrolled in one of the residential rates above and a rate-enabled mechanical solution (rate-enabled thermostats or hot water heater) have a reduced peak load impact, based on the peak load end use share of heating and hot water usage, to account for the fact that the load impact is considered in mechanical solutions, preventing any double counting.

NON-RESIDENTIAL RATES DETAILS

SMALL C&I CUSTOMERS – BILL CERTAINTY WITH PTR

Being a segment with historically low elasticity to electric demand, this rate was implemented as being the most consumer friendly, hoping to spur demand response. The rate offers a fixed bill per month, with a PTR on peak days.

- **Peak to off-peak ratios**
  - 3:1 saving ratio[18]
  - Peak impact reduction was also derived from the Arcturus[19] analysis on dynamic rates. This analysis evaluates the customer peak reduction to dynamic rates, covering more than 300 pricing treatments from over 60 pilots.
  - Bounce back effects apply the residential PTR shape, adjusted to savings levels derived for C&I customers.
- **Eligible Market**
  - Customers in either DEC – SGS or DEP – SGS

Although the Flex Savings Options Pilot also included customers from the SGS rate class, results were not yet available to integrate into our analysis. Instead, the Arcturus report was used, but savings were

[18] For example: With an average cost of electricity over the fixed bill is 15¢/kWh, the rebate would be 30¢/kWh, for a total discount of 45¢/kWh, which is three times to initial cost of electricity.

[19] Peak reduction from “Arcturus 2.0: A meta-analysis of time-varying rates for electricity”, A. Faruqui, S. Sergici and C. Warner, 2017.

reduced by 50% compared to residential customer response to account for the historically low elasticity of the small C&I sector.

MEDIUM AND LARGE C&I RATES – PTR

By using a carrot-only rebate approach, PTR rates is particularly attractive to large customers who see in it as a win-win situation. Considering the variety of C&I rates as well as the option for large customers to opt-out from DSM programs, this rate is potentially an opportunity to attract more customers than current DSM programs. The rate consists of offering a rebate for reducing their load below a customer-specific baseline during peak times.

- **Peak load impact**
    - Peak impact reduction was assessed based on an end-use approach where the percentage of achievable load curtailable by customer was evaluated for each major end-use. Baseline load curves are based on hourly average demand per customer class provided by Duke Energy.
- **Eligible Market**
    - All C&I customers can choose to enroll (DEC – LGS, DEC – OPTC, DEC-OPTI, DEC – Other, DEP MGS, DEP – LGS). It is assumed that a small portion of opt-out customers would choose to enroll in the rates (more details in the results section)
    - For modelling assumptions, to avoid any double-counting, participants already enrolled under current DSM programs (DRA or PowerShare) are excluded from the customers count.